BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

In the Matter of the Application of	)	
	)	
HAWAIIAN ELECTRIC COMPANY, INC.	)	**Docket No. 2008-0303**
HAWAII ELECTRIC LIGHT COMPANY, INC.	)	
MAUI ELECTRIC COMPANY, LIMITED	)	
	)	
For Approval of the Advanced Meter Infrastructure (AMI) Project and Request to Commit Capital Funds, to Defer and Amortize Software Development Costs, to Begin Installation of Meters and Implement Time-Of-Use Rates, for Approval of Accounting and Ratemaking Treatment, and other matters.	)	

FILED
2009 JUL 31 P 4: 18
PUBLIC UTILITIES COMMISSION

Advanced Metering Infrastructure (AMI) Project

Hawaiian Electric Companies' Direct Testimonies

July 31, 2009

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

Dean K. Matsuura
Manager
Regulatory Affairs

July 31, 2009

The Honorable Chairman and Members of the
Hawaii Public Utilities Commission
Kekuanaoa Building, 1st Floor
465 South King Street
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Docket No. 2008-0303
Advanced Metering Infrastructure Project
Hawaiian Electric Companies' Direct Testimonies

In accordance with the *Order Approving Stipulated Procedural Order, as Modified*, filed on April 21, 2009, enclosed for filing are the Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited's (collectively "Hawaiian Electric Companies") Direct Testimonies.

Very truly yours,

Dean K. Matsuura

Enclosures

cc: Division of Consumer Advocacy
Henry Q Curtis (Life of the Land)
Warren S. Bollmeier II (HREA)
Mark Duda (HSEA)

HECO T-1
DOCKET NO. 2008-0303

TESTIMONY OF
LEON R. ROOSE

MANAGER, SYSTEM INTEGRATION DEPARTMENT
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: AMI BUSINESS POLICY

INTRODUCTION

Q. Please state your name and business address.

A. My name is Leon Roose and my business address is 820 Ward Avenue, P.O. Box 2750, Honolulu, Hawaii.

Q. By whom are you employed and in what capacity?

A. I am Manager of the System Integration Department (formerly the System Planning Department) of Hawaiian Electric Company, Inc. ("Hawaiian Electric").

Q. Please state your professional experience and educational background.

A. My experience and educational background are provided in HECO-100.

Q. What is the scope of your testimony in this proceeding?

A. I am the policy witness on the Advanced Metering Infrastructure ("AMI") Project proposed by Hawaiian Electric, Hawaii Electric Light Company, Inc. ("HELCO"), and Maui Electric Company, Ltd. ("MECO") (collectively, the "Hawaiian Electric Companies" or "Companies"). The following individuals will also present testimony in the instant proceeding on behalf of the Companies:

HECO T-2 – Mr. Fetherland – AMI Technology and Project Implementation
HECO T-3 – Mr. Hignite – Cost-Benefit Analysis
HECO T-4 – Mr. McMenamin – Customer Information System ("CIS") Project
HECO T-5 – Ms. Nanbu – Accounting Treatment and Cost Recovery
HECO T-6 – Ms. Sekimura – Need for Accelerated Cost Recovery
HECO T-7 – Mr. Young – Time-of-Use ("TOU") Rates

GENERAL AMI POLICY

Q. What is the Hawaiian Electric Companies' general policy on AMI?

A. The Hawaiian Electric Companies view AMI as a technology that can provide fundamental improvements in labor intensive processes while improving our ability to serve our customers and serving as a foundational element of the Smart Grid. Keys to the success of both AMI and the Smart Grid are reliable, two-way communication networks and the availability of low-cost, high-functionality hardware (including residential and commercial and industrial meters and distribution automation devices for the grid). The presence of a pervasive two-way communication network throughout the Companies' service territories will enable the utilities to implement rates and programs to engage customers in the active management of their electricity use and also provide a new means to monitor operating conditions within the Companies' systems. A new awareness of electricity consumption (made possible by the AMI system) will ultimately modify customer behavior – in a similar fashion to drivers who have purchased automobiles with real-time displays of fuel consumption, which some have coined the "Prius-effect."

HAWAIIAN ELECTRIC COMPANIES' PROPOSED AMI PROJECT

Q. What are the Hawaiian Electric Companies requesting in this docket?

A. As described in the instant Application, the Companies are requesting the following:

(1) to commit capital funds in excess of $2,500,000 (estimated at $41,229,000 for Hawaiian Electric, $10,606,000 for MECO, and $13,190,000 for HELCO) for the AMI project;

(2) to defer certain computer software development costs (i.e., the "Stage 2" or "Application Development" costs, including the costs of designing, acquiring, installing and testing the computer software) for the Meter Data Management System ("MDMS") and accrue an allowance for funds used during construction ("AFUDC") during the deferral period (total deferred costs are estimated at $9,134,000 for Hawaiian Electric, $2,021,000 for MECO, and $2,385,000 for HELCO);

(3) to amortize the MDMS deferred costs (including AFUDC) over a 12-year period (or such other amortization period as the Commission finds to be reasonable), and to include the unamortized deferred costs (including AFUDC) in rate base;

(4) cost recovery for ratemaking purposes of the remaining book value of its existing meters (that will be replaced with advanced meters) in the following manner for each of the Companies:

(a) Hawaiian Electric – beginning with the receipt of the Commission's Decision and Order on a straight-line basis over a period of three years for Hawaiian Electric,

(b) MECO – beginning with the receipt of the Commission's Decision and Order on a straight-line basis and ending when MECO's meter installation begins, and

(c) HELCO – beginning with the receipt of the Commission's Decision and Order on a straight-line basis and ending when HELCO's meter installation begins;

(5) cost recovery for ratemaking purposes of the capital costs associated with the purchase and installation of the new AMI meters over a seven-year period on a straight-line;

(6) immediate approval to begin installing, on a first-come, first-served basis, advanced meters for all customers that request them and to implement TOU rates on an interim basis for customers requesting the installation of advanced meters;

(7) expedited approval of proposed Schedule TOU-R (Residential Time-of-Use) rates for Hawaiian Electric, HELCO, and MECO (all three divisions) and proposed Schedule TOU-G (Small Commercial Time-of-Use Service), Schedule TOU-J (Commercial Time-of- Use Service) and Schedule TOU-P (Large Power Time-of-Use Service) rates for HELCO and MECO (all three divisions);

(8) to recover all of the Companies' incremental cost associated with the AMI Project through the Renewable Energy Infrastructure Program ("REIP") surcharge ("REIP Surcharge") that is pending approval in

Docket No. 2007-0416 or an AMI surcharge ("AMI Surcharge") mechanism approved by the Commission in this proceeding;

(9) approval of the Advanced Metering Infrastructure Equipment and Services Agreement ("Sensus Agreement") between the Hawaiian Electric Company, Inc. and Sensus Metering Systems, Inc. ("Sensus") including its terms and conditions and a finding that the arrangement is prudent and in the public interest, and a determination that the Companies may include all costs, fees and related taxes to be paid by the Companies pursuant to the Agreement in its revenue requirements for ratemaking purposes and for the purposes of determining the reasonableness of the Companies' rates; and

(10) to recover the lease expenses (based on lease payments over the term of the agreement) for the Sensus-owned, two-way radio frequency network infrastructure ("AMI Network").

PROJECT BENEFITS AND IMPACTS

Q. What are the near-term benefits of the proposed AMI Project?

A. In the near-term, AMI implementation will provide labor savings and allow the Companies to provide more granular and timely information to their customers, either through a web portal or directly through an in-home display. AMI will improve the accuracy, timeliness and cost efficiency of billing information, and customers will have greater confidence in the bills they receive. The availability of recent energy usage information will also empower customers to make more intelligent energy decisions and have greater control over their energy use and costs. Customer equity will also be enhanced through improved meter accuracy and electricity theft detection made possible by the AMI system. In-home and embedded appliance devices becoming available in the marketplace allow customers to view consumption information almost immediately and also provide a means to program and control major appliances. The ability of the AMI Network to control devices or appliances at the customer's premises will provide an important tool to support the integration of increased levels of renewable and distributed generation energy sources into the Companies' grids.

Q. Are there longer-term benefits of AMI as well?

A. Yes. In the longer term, the AMI Project will support distribution planning, system operation, and outage detection and restoration through the availability of system status information (for example, voltage and power measurements) and momentary outage counts (or "blinks") at each customer premises throughout the Companies' grids. The Companies are also investigating the ability of the AMI Network to provide grid control functions such as remote switching and event capture (i.e., alerts and alarms) from the distribution system.

The AMI Project proposed by the Hawaiian Electric Companies will help to usher in a clean energy future for Hawaii and foster an ethic of energy efficiency – a goal shared by the State of Hawaii and the Hawaiian Electric Companies. In particular, the AMI system that the Companies propose to install will: 1) provide a number of presently quantifiable long-term benefits resulting from meter reading, field service and meter capital savings, as well as increased customer equity through heightened meter accuracy and energy theft reductions; 2) enable and support the wider adoption of TOU pricing; 3) enable future programs such as Dynamic Pricing; and 4) support a future Smart Grid. The proposed AMI Project is designed to meet all of these objectives and the Companies urge the Commission to grant approval to move forward.

Q. Please elaborate on the Companies' goals with respect to energy efficiency.

A. Although achieving an ethic of energy efficiency has been a goal of the Hawaiian Electric Companies for some time, it recently became a legislative mandate. On June 25, 2009, the Governor of the State of Hawaii signed into law Act 155, H.B. No. 1464, H.D. 3, S.D. 2, C.D. 1 ("Act 155"), thereby aggressively increasing the clean energy obligations of electric utilities in Hawaii. Part VI of Act 155 expressly directs the Commission to establish "energy-efficiency portfolio standards that will maximize cost-effective energy efficiency programs and technologies." More specifically, Act 155 requires that the energy-efficiency portfolio standards be designed to achieve 4,300 GWh of electricity use reductions statewide by 2030, with interim Commission-established goals for 2015, 2020, and 2025. The Commission "may also adjust the 2030 standard to maximize cost-effective energy-efficiency programs and technologies."

Q. How much will the AMI Project cost?

A. The total AMI Project costs of $115,016,000 from 2010 through 2015 can be summarized as follows: (1) Capital Costs of $68,784,000; (2) Deferred Costs of $13,540,000; and Expense Costs - $32,692,000.

Further details regarding AMI project benefits and cost are provided by Mr. Hignite in HECO T-3.

Q. What are the estimated bill impacts of the AMI Project on the Companies' customers?

A. As indicated in Exhibit 21 of the instant Application, the Companies estimate that monthly impacts on customer bills will range from an increase of $0.80 to $3.50

for customers consuming 1,000 kWh/month.

ROLE OF AMI IN THE CLEAN ENERGY FUTURE

Q. How will the AMI Project help to move Hawaii toward a clean energy future and an ethic of energy efficiency?

A. The AMI Project will promote Act 155's energy efficiency objectives by, among other things, empowering customers to make more intelligent energy decisions and have greater control over their energy use and costs. AMI also supports many of Hawaii's other and/or related clean energy objectives including the Smart Grid, the greening of transportation, demand response programs, pricing principles and programs, distributed generation, distributed energy storage, net energy metering and investment in infrastructure.

In particular, AMI is a foundational element of a Smart Grid future, and the Companies have initiated the development of a Smart Grid roadmap to define and analyze the benefits and costs of various elements of a Smart Grid and guide the timeframe over which a Smart Grid can be developed. The Companies are in the process of finalizing a request for proposals ("RFP") for consulting services to complete a Smart Grid roadmap and through the RFP process, will select a firm to develop individualized roadmaps charting a Smart Grid course for each of the Companies.

Q. What is the Companies' perspective on the recent rapid evolution of AMI technology and its relationship to the Smart Grid?

A. From the time that the Companies first considered available AMI products several years ago, the technology has rapidly evolved beyond simple automated metering into a foundational technology that supports the Smart Grid by providing information from the Companies' customers and the distribution grid itself through a two-way communications network. Thus, AMI Networks in particular have moved to the forefront as a key Smart Grid enabling technology, and AMI vendors have responded enthusiastically by a near explosive expansion of product offerings (ranging from utility distribution automation functions to customer in-home displays and controls) and development of synergistic capabilities between AMI and Smart Grid applications. Thus, the Companies believe that AMI technology and its communications network will undoubtedly be a central and essential element in many aspects of the Companies' future Smart Grid initiatives.

CONCLUSION

Q. Please summarize your testimony.

A. The Hawaiian Electric Companies have proposed an AMI system that provides immediate quantifiable benefits to the utility and its customers. These benefits will help to offset the reasonable costs of the AMI system and provide a foundation for future programs which will help the Companies in areas such as distribution planning, system operation and automation, customer outage identification and restorations, customer operations and billing, and customer energy use awareness and efficiency. Ultimately, an AMI system will also help to increase the utilization of renewable energy resources.

The Consumer Advocate, the Hawaii Renewable Energy Alliance, the Hawaii Solar Energy Association and Life of the Land, as well as the Commission's consultant, the National Regulatory Research Institute, have provided valuable insight and views on many aspects of the Companies' proposed AMI Project, including the selection of an optimal AMI system. AMI will help the Hawaiian Electric Companies meet their energy efficiency goals, while enabling important clean energy efforts such as Smart Grid, TOU pricing, demand response and renewable energy integration initiatives, and providing an opportunity for the Companies and the parties to this docket to collaborate in building a clean energy future for Hawaii. Approval of the proposed AMI Project will create an opportunity to move forward on clean energy objectives by bringing "smart" capabilities and programs to life today in a form that brings value and makes sense to our customers, and can be leveraged as a platform upon which further benefits will be realized in time.

Q. Does this conclude your testimony?

A. Yes, it does.

HAWAIIAN ELECTRIC COMPANY, INC.

LEON R. ROOSE

EDUCATIONAL BACKGROUND AND EXPERIENCE

BUSINESS ADDRESS:	*Hawaiian Electric Company, Inc.* 820 Ward Avenue P. O. Box 2750 Honolulu, HI 96840
CURRENT POSITION:	Manager, System Integration Department (formerly, System Planning Department)
YEARS OF SERVICE:	16 Years
EDUCATION:	Juris Doctor – William S. Richardson School of Law University of Hawaii, Manoa (1990 – 1993) Bachelor of Science – Electrical Engineering University of Hawaii, Manoa (1983 – 1988)
EXPERIENCE:	January 2007 – Present Manager, System Integration Department (formerly, System Planning Department) HECO September 2004 – January 2007 Manager, Power Supply Services Department HECO October 1996 – September 2004 Associate General Counsel, Legal Department HECO February 1996 – October 1996 Planning Engineer, Planning & Engineering Department HECO

EXPERIENCE: (continued)	June 1993 – February 1996 Attorney, Damon Key Bocken Leong Kupchak Practice focused in business, corporate, intellectual and real property law; general civil litigation
	May 1990 – January 1992 Analyst Temp, Rate and Regulatory Affairs Department HECO
	June 1988 – August 1990 Designer I, System Planning Department HECO
	1986- 1988 Engineering Analyst Naval Ocean Systems Center
OTHER PROFESSIONAL EXPERIENCE:	April 2008 Utility Wind Integration Group Annual Meeting and Technical workshop – Fort Worth, TX
	July 2007 Utility Wind Integration Group Annual Meeting and Technical workshop – Anchorage, AK
	June 2005 Utility Executive Course University of Idaho – Corporate Utility Training Program
TESTIMONY:	UPC Hawaii / Kaheawa Wind Power II Complaint Docket No. 2008-0021
	Competitive Bidding for New Generation Docket No. 03-0372

HECO T-2
DOCKET NO. 2008-0303

TESTIMONY OF
PAUL FETHERLAND

DIRECTOR
ADVANCED METERING INFRASTRUCTURE (AMI) DIVISION
SYSTEM INTEGRATION DEPARTMENT
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: AMI Project

- Technology
- Project Need
- Programs Enabled By AMI
- AMI Deployment
- Technology Evolution
- AMI Integration With Other Systems
- Information Security

INTRODUCTION

Q. Please state your name and business address.

A. My name is Paul Fetherland and my business address is 820 Ward Avenue, Honolulu, Hawaii.

Q. By whom are you employed and in what capacity?

A. I am the Advanced Metering Infrastructure ("AMI") Director for Hawaiian Electric Company, Inc. ("Hawaiian Electric").

Q. Please state your professional experience and educational background.

A. My experience and educational background are provided in HECO-200.

Q. What is the scope of your testimony in this proceeding?

A. I am responsible for describing the overall AMI Project and the following elements of the AMI Project proposed by Hawaiian Electric, Hawaii Electric Light Company, Inc. ("HELCO"), and Maui Electric Company, Limited ("MECO") (collectively, the "Hawaiian Electric Companies" or "Companies"):

1. Technology
2. Project Need
3. Programs Enabled By AMI
4. AMI Deployment
5. Technology Evolution
6. AMI Integration With Other Systems
7. Information Security

AMI PROJECT

Q. What is AMI?

A. AMI refers to the system infrastructure that measures, collects and analyzes energy usage, on a pre-defined schedule or "on demand" basis. This infrastructure includes hardware, software, and communication systems, ultimately linking customer premises advanced electricity meters to utility-located systems. AMI provides two-way, wireless communications between utilities and customer meters to allow utilities to obtain consumption reads and voltage status at individual premises much more frequently than the existing monthly meter reading cycles, as well as "on demand."

Q. What are primary components of the Companies' proposed AMI system?

A. The AMI system is comprised of advanced meters and a two-way wireless network, both provided by Sensus Metering Systems, Inc. ("Sensus"), and a meter data management system ("MDMS"). (The Companies executed a comprehensive agreement with Sensus ("Sensus Agreement") on October 1, 2008, under which the Companies will purchase residential and commercial AMI meters.) The MDMS will be centralized at Hawaiian Electric and provide for the integration of the MDMS with the Companies' customer information system ("CIS"). The AMI Network provides communication between the AMI meters and the MDMS.

Q. How would the proposed AMI system be deployed?

A. AMI meters and components of the AMI Network will be installed on the islands of Oahu, Maui and Hawaii. Residential AMI meters will be installed by: (1) a meter installation vendor (to be selected via a request for proposal ("RFP") selection process); (2) the Companies' internal labor force; or (3) a combination of the two. The commercial and industrial ("C&I") AMI meters will be installed by the Hawaiian Electric Companies' internal labor force.

Overall, Hawaiian Electric is planning for a six-year AMI Project implementation, beginning in 2010. The AMI Project will begin with the development of the first phase of the MDMS in 2010 at Hawaiian Electric's data center on Oahu. The installation of Oahu's AMI Network will occur incrementally, beginning in November 2010 and progressing through August 2013. Full-scale meter deployment on Oahu will begin in May 2011 and end in December 2013. The installation of Maui's AMI Network will occur incrementally, beginning in November 2013 and progressing through September 2014. Full-scale meter deployment on Maui will begin in April 2014 and end in December 2014. The installation of the AMI Network on the island of Hawaii will occur incrementally, beginning in October 2014 and progressing through August 2015. Full-scale meter deployment on the island of Hawaii will begin in April 2015 and end in December 2015.

These schedules are planning estimates and will need to be adjusted if steps required to move forward such as Commission approval and MDMS development require more time.

TECHNOLOGY

Q. How would the AMI system work?

A. The proposed AMI system would consist of advanced meters, two-way wireless communications networks, a network management and control system (i.e., a regional network interface or "RNI"), and the MDMS. The meters and MDMS will be owned by the Hawaiian Electric Companies while the RNI and the two-way wireless communications network will be owned by the AMI vendor. All of the advanced meters will have the capability to capture interval meter reads at configurable intervals (such as 15-minute or one-hour) and deliver encoded and encrypted data to the RNI, which will be operated and maintained by the AMI vendor but located at the Hawaiian Electric Companies' secure data center in Honolulu. A backup data center will be located at another secure data center facility in order to provide for disaster recovery. Both the residential and C&I meters will capture and transmit outage and restoration events as well as voltage data.

Meter data from the RNI will be transmitted to the Hawaiian Electric Companies' MDMS, which will store and process the meter data through a process known as validation, editing and estimating. Processed data from the MDMS will be delivered in a suitable format to the Companies' CIS. In the near term, this will be the legacy CIS. Interface and system of record definitions will be formalized during the MDMS design process.

Q. What type of technologies will the AMI Project employ?

A. The Hawaiian Electric Companies' current AMI plans call for the implementation of a fixed tower AMI system. The Companies would install utility-owned Sensus iConA residential meters and Elster C&I meters equipped with Sensus FlexNet radio boards. In high customer turnover areas, just over 4% of the residential meters would be equipped with an integrated remote disconnect switch that facilitates remote start/stop operations and remote reads by the Hawaiian Electric Companies' customer service representatives.

The Hawaiian Electric Companies' plans also include the installation of 900 MHz, licensed frequency, AMI networks using base stations (Tower Gateway Base Stations or "TGBs") strategically located throughout the islands of Oahu, Maui and Hawaii, which networks will be owned and operated by the Companies' AMI vendor. In isolated areas or other areas which are difficult to cover economically, network or remote portals (i.e., FlexNet Remote Portals or "FRPs" and FlexNet Network Portals or "FNPs") will be installed. FNPs and FRPs would be mounted on poles, buildings or other structures. The Companies' AMI vendor will be obligated to provide minimum network performance levels in return for payment of a monthly per endpoint fee by the Hawaiian Electric Companies.

PROJECT NEED

Q. Is there a clearly defined need for the AMI project?

A. Yes. AMI provides two-way communications between the utility and customer meters to allow the utility to obtain consumption reads and voltage status at individual premises much more frequently than the monthly billing cycle, and "on demand." These capabilities can allow the Companies to enhance customer service, revenue management and distribution operations, and support outage management.

In conjunction with a future demand response ("DR") program, AMI will empower the Companies' customers to reduce and/or shift energy usage in response to time-differentiated energy prices. Further, DR technologies, such as smart programmable/controllable thermostats, smart load cycling controls, inpremise displays, etc., can allow customers to execute their choices conveniently.

The AMI communication and smart metering infrastructure also provides a foundation for the implementation of Smart Grid technology. Smart Grid technology combines intelligent electronic devices (i.e., smart relays and distribution automation devices) and advanced applications that utilize timely data on customer loads and voltages. The Smart Grid promises unparalleled capabilities in monitoring, controlling, optimizing and automating the restoration of the electric power delivery system. Collectively, AMI and DR offer important alternatives, in addition to renewable energy, to help address global energy supply and environmental issues.

In short, the implementation of AMI is being driven by significant developments in the evolution and availability of AMI-related technologies, AMI's increasing popularity on the U.S. mainland, and uncertainty in the future price of fuel. AMI has – particularly in recent years – received wide support at both state and federal levels.

Q. What are the specific objectives of the AMI Project?

A. The Companies' specific objectives with respect to the AMI project are:

(1) install remotely configurable and upgradable, advanced meters for the majority[1] of the Companies' residential and C&I customers;

(2) provide 15-minute or one-hour[2] interval data to customers through the Companies' web portal or directly to future devices such as in-home displays;

---

[1] In response to the Consumer's Advocate's concern about customer equity, the Hawaiian Electric Companies' revised its proposed meter replacement count to 100% of the meters that are classified as non-MV90 meters, which are connected by phone lines.

[2] The advanced meters selected by the Hawaiian Electric Companies can be configured to provide as low as 5-minute interval data.

(3) interface the AMI system's MDMS to the Companies' CIS;

(4) provide a pervasive, flexible, wireless, and two-way communications technology that can support monitoring, sensing, and control of the utility grid as well send price and control signals, status messages (tampers, power outage and restoration, voltage minimum/maximum/average, and voltage profile information to and from each customer's premises;

(5) provide an AMI platform that supports future HANs;

(6) reduce manually intensive labor cost through significant elimination of meter reading and field services time;

(7) improve customer service through more timely acquisition and granularity of data and outbound control functionality (e.g., remote connection and disconnection of selected meters and on-demand reads);

(8) provide metering which is inherently accurate and persistent compared to old electromechanical meters;

(9) provide minimum/maximum/average voltage and voltage profile data to distribution planning and system operations;

(10) provide momentary outages ("blink counts") to system operations; and

(11) support outage management functions and examine the means to leverage the availability of outage and restoration alarm data by Hawaiian Electric's outage management system ("OMS") and in a simpler fashion with MECO and HELCO.

Q. Has the Consumer Advocate expressed any concerns regarding how the AMI Project is defined?

A. The Consumer Advocate expressed a concern regarding the clarity of the AMI project's definition. The Consumer Advocate's position is partially based on total project cost and other factors, including a reference to the Commission's Decoupling proceeding, Docket No. 2008-0274.

The AMI Project that has been defined by the Hawaiian Electric Companies would replace all of its customer's meters (except those C&I customers with existing MV90 meters connected by phone lines) with advanced meters, capture interval data, provide that data to customers through the web, and allow time-of-use ("TOU") rates to be widely implemented throughout the Companies' customer base, while providing a platform for future programs. The costs and benefits of AMI Project are detailed in Mr. Hignite's testimony (HECO T-3).

Q. Is the Hawaiian Electric Companies' proposal to implement the AMI Project reasonable?

A. Yes. The Companies proposed the AMI project as a first step in a broader Smart Grid initiative, focusing on quantifiable benefits that provide near term benefits to the utility and its customers. To properly assess the reasonableness of the AMI Project, a detailed AMI financial model was developed by the Hawaiian Electric Companies. The results of the model indicate that a substantial portion of the AMI Project cost would be offset by currently quantifiable benefits. Additional benefits will result from the implementation of the AMI Project, but they are difficult to quantify at this time. The Dynamic Pricing Pilot ("DPP") Program, once approved by the Commission, will allow the Hawaiian Electric Companies to better understand the costs and benefits of such pricing programs, and how this would affect the AMI Project's benefit-cost ("B/C") ratio. In the case of Pacific Gas & Electric's AMI program, these future DR benefits increased the benefit-cost ratio above unity.

In order to capture the important features of the AMI Project, the AMI financial model (see HECO T-3) is detailed and contains a myriad of assumptions, including project timing. The Consumer Advocate expressed concern about the cost effectiveness of the AMI project and was unable to develop a position due to time constraints, unfamiliarity with the financial model, and lack of competitive vendor pricing for comparison purposes.

Mr. Hignite's testimony (HECO T-3) discusses the Companies' financial model, including the quantifiable costs and benefits and assumptions that were used to calculate the B/C ratios that were presented in the Companies' response to CA-IR-3 (including Attachment 1 of the Companies' response).

PROGRAMS ENABLED BY AMI

Q. How could AMI be leveraged to support DR programs?

A. The AMI network is designed to provide two-way communications with devices such as load control switches, thermostats, and in-home displays to allow the management of electricity use by water heaters, air-conditioning units, pool pumps and smart appliances. Exhibit 13 of the Application provided a Sensus white paper that described their DR roadmap. Since the time that this white paper was written (February 2008), the industry has advanced and more products are becoming available in the marketplace to support DR programs.

Q. What are the other parties' views on programs enabled by AMI?

A. The Consumer Advocate's direct testimony indicates support for Commission approval of the Hawaiian Electric's DPP Program (Docket 2008-0074) and acknowledges that this is the exact type of program that a cost-effective AMI system will facilitate since, without such an AMI system, the Companies would primarily have to rely on non-integrated systems and/or manual effort to implement and calculate rebates. The Consumer Advocate further indicates that, without a cost-effective AMI system, the Companies would be essentially prohibited from offering such programs to all customers or even to some of the customer classes in their entirety.

Q. Does the AMI system proposed by the Hawaiian Electric Companies include Home Area Network ("HAN") functionality?

A. The AMI meters selected by the Hawaiian Electric Companies rely on FlexNet HAN devices within a home or business. Such devices would be procured directly from the AMI vendor or through a third-party vendor who has licensed FlexNet technology and has embedded this capability into their HAN product line. In addition, many HAN product vendors are also designing products that can utilize a device adapter called USNAP[3] to act as a translator between FlexNet and more common communication protocols such as ZigBee, which is a popular with many large mainland utilities. HANs are not a part of the instant Application, but provide a mechanism to leverage the AMI Network to extend control within a customer's premises and added benefits to customers and the utility in the future, particularly with the advent of smart appliances.

AMI DEPLOYMENT

Q. Please describe the extent of the Hawaiian Electric Companies' planned AMI deployment?

[3] USNAP denotes Utility Smart Network Access Port. Details are available at http://www.usnap.org

A. The proposed AMI Project would deploy approximately 478,000 residential and C&I meters on the islands of Oahu, Maui and Hawaii over a six-year period.

Q. How do the Hawaiian Electric Companies propose to deploy AMI?

A. The Companies have laid out a realistic deployment timeframe, which we believe is practical and effectively balances internal and external resources for AMI deployment across the islands of Oahu, Maui and Hawaii. AMI deployment would take place on Oahu first over a three-year period, followed by the islands of Maui and Hawaii in subsequent years. In contrast to mainland projects, manpower is not as readily available in Hawaii for long-term meter deployments; therefore, the Hawaiian Electric Companies' plan to maximize the use of internal personnel from the metering and field services areas. The Companies also believe that the active involvement of internal field personnel provides a higher level of confidence that the installations will go smoothly and mitigate adverse impacts on our metering operations, which are critical to our overall business.

From an information technology perspective, the Hawaiian Electric Companies have also proposed a phased approach to mitigate risks and ensure that core software is functioning properly before proceeding with more complex system features. The Consumer Advocate has expressed concern about the linkage of the MDMS to the CIS, including the reliance of the overall AMI project benefits on the successful implementation of both software systems. This is addressed by Mr. McMenamin in HECO T-4.

Q. Did any of the parties express concerns regarding the Companies' deployment plan?

A. Yes. The Consumer Advocate questioned whether the deployment could be accelerated to achieve benefits faster, but the Hawaiian Electric Companies believe that this would create unnecessary risk. The Consumer Advocate also suggested that deployment plans target areas where the highest benefits could be achieved (i.e., with remote disconnect meters and/or remote or difficult to read areas). To the extent practicable, the Companies would consider alternatives to accelerate the realization of AMI benefits, but need to balance such an objective against meter deployment efficiency. AMI deployments rely on rapid and persistent meter rollouts in order to achieve the necessary cost efficiency, to the extent that resources are available and can be effectively managed.

<u>Molokai and Lanai</u>

Q. The Consumer Advocate expressed concern about the availability of advanced meters on the islands of Molokai and Lanai, and discussed in its direct testimony the use of alternative AMI technologies such as mesh AMI systems that might be more cost-effective for smaller meter populations. Do the Hawaiian Electric Companies plan to deploy AMI on Molokai and Lanai?

A. Yes. The current plan is to examine AMI technologies for the islands of Molokai and Lanai after completing the initial six-year deployment of AMI on Oahu, Maui and the Big Island.

Q. What other concerns have been expressed regarding the proposed AMI deployment plan relative to Molokai and Lanai?

A. The Consumer Advocate asserts that there is a need to transition to processes and procedures that will raise consumer awareness of energy consumption patterns and other related information. The Consumer Advocate further indicates that it is unlikely that successful DR programs (such as dynamic pricing programs), TOU meters, etc. can be implemented on the islands of Molokai and Lanai without

AMI, thereby unnecessarily and/or inappropriately excluding a customer or customer class.

As discussed in the Companies' responses to CA-IR-11 and CA-IR-16, the Companies' currently proposed project does not include any costs or benefits for AMI on the islands of Molokai and Lanai and the Companies' plan was to file a request with the Commission to provide AMI metering to these islands later in the project. If requested by the Commission, a revised project plan can be developed to address the provision of these two islands with AMI meters in a more accelerated manner.

Mitigating Delays

Q. The Consumer Advocate has expressed a concern over project delays. Are there measures in place to address this concern?

A. Yes. This is a reality that the Hawaiian Electric Companies have foreseen and the Sensus Agreement contains delay penalties that will help to mitigate these delays. The major concerns that the Companies have in this area are (1) delay penalties levied by the installation contractor(s) including potential re-mobilization costs, and (2) manufacturing delays or defects that cause major delays in product shipment. During deployment, the Companies will maintain an initial buffer stock of 10,000 meters and Sensus will be subject to delivery penalties specified in the Sensus Agreement. The Hawaiian Electric Companies will be obligated to support Sensus by timely ordering and reasonable projection of monthly meter needs. This collaboration is intended to provide a buffer and avoid potential delay penalties by the meter deployment contractor.

100% Meter Replacement

Q. What percentage of the Companies' existing meter population does the Companies intend to replace with advanced meters?

A. The Companies initially expected to replace 95-96% of customers' existing meters with AMI meters. However, in partial response to a customer equity issue raised by the Consumer Advocate, the Companies revised their AMI project design basis to allow for replacement of substantially all of their customers' meters with AMI meters (except for existing MV90 meters). To a certain extent, a more homogeneous population of meters will result in lower costs. (See page 12 of CA-T-1). Admittedly, decreasing the population diversity of the Companies' meters would simplify staff training and maintenance costs to an extent; however, cost savings from meter and spare parts inventory would be minimal since the Hawaiian Electric Companies have already worked to minimize meter diversity within their inventory. Meter repairs and recalibration are only performed on specialized C&I meters; in most cases the meter is simply replaced or returned to the manufacturer if it has failed within the warranty period.

First-Come, First-Served Meter Installation

Q. Is the proposed implementation schedule that results in the meters being installed on a first-come, first-served basis with the possibility of allowing customers an opt-out basis reasonable?

A. Yes. Mr. Young's testimony (HECO T-6) discusses TOU and dynamic rate options and the rationale for opt-in, opt-out and mandatory participation by customers.

TECHNOLOGY EVOLUTION

Q. Is AMI technology evolving?

A. Yes. The Companies have observed a rapid (and recent) evolution of products and technologies in the AMI and Smart Grid marketplace. The pace of change has been significantly accelerated by the promise of federal project funding through the American Recovery and Reinvestment Act ("ARRA"). As a result of this, as well as concerns expressed by the Consumer Advocate and the other parties[4] to this docket, the Hawaiian Electric Companies initiated research and entered into discussions with leading AMI vendors, with a particular focus on communication networks, distribution automation and national standards, which collectively are proving to be critical elements of the foundation for a Smart Grid. In particular, the Consumer Advocate and other parties to this docket have expressed concerns regarding optimal technology selection. This is understandable given the rapid movement in the AMI marketplace as meter vendors moved to address utilities' interest in utilizing AMI networks to support distribution automation ("DA") and DR functionality (subsets of the Smart Grid). The Hawaiian Electric Companies are working with Sensus in order to obtain a detailed understanding of their Smart Grid business and product roadmap.

Q. Has the Consumer Advocate raised any concerns with respect to the Companies' AMI technology selection?

A. The Consumer Advocate has expressed concern that the Hawaiian Electric Companies did not employ a competitive RFP process for the AMI meters and network and have not yet completed the RFP process for the MDMS (and system

[4] The other parties include Hawaii Renewable Energy Alliance, Hawaii Solar Energy Association, and Life of the Land.

integrator services). As a result, the Consumer Advocate asserts that it is unable to make a comparative assessment of the cost-effectiveness of the proposed AMI Project.

The Hawaiian Electric Companies are aware that selection and integration of the MDMS is a critical part of the overall AMI system. In fact, due to the critical nature of this selection, the rapid evolution of the MDMS product marketplace, and implementation challenges encountered by other utilities in successful implementations of AMI front-end software to MDMS and CIS systems, the Companies expanded their MDMS vendor evaluations to include three additional vendors (Ecologic Analytics, Aclara Software, and Oracle Lodestar).

The initial two MDMS systems that were evaluated under pilot agreements at Hawaiian Electric were Itron and eMeter. All five of the MDMS vendors count major utilities as their customers and are in the process of implementing or going live with their software. Some of the MDMS vendors are also moving into the DR marketplace. The Hawaiian Electric Companies plan to develop a comprehensive MDMS and System Integration RFP, leveraging the preliminary functional requirements that were developed with Enspiria Solutions earlier as well as the knowledge gained during the Hawaiian Electric Companies' pilot MDMS activities.

Q. Besides issues related to the MDMS, are there other questions that could, or should, be asked regarding the AMI solution proposed by the Companies?

A. The Consumer Advocate questions whether the Companies have thoroughly evaluated all of the possible options to determine the optimal AMI system solution, including the possibility of using a hybrid solution rather than a single technology. The Consumer Advocate cites the scenario on Molokai and Lanai, whereby a second technology may have provided a practical solution to the Sensus fixed tower network. The Consumer Advocate's observations are more relevant in today's AMI marketplace when compared to a technology decision made several years ago, when AMI technology (including Sensus) was in a less mature state.

In discussions with AMI consultants who are familiar with the marketplace, the rapid evolution of AMI technology and products over the past several years and the rising visibility of communications networks as the keys to the future Smart Grid have placed many utilities in situations where technology selection has taken on a whole new challenge. A notable situation occurred when Pacific Gas & Electric transitioned from a low speed, powerline carrier ("PLC") system[5] to an Internet-Protocol (IP) based, wireless network after the installation of 600,000 PLC meters. A credible argument can be made that there is a constant evolution in AMI technologies and that waiting for the ultimate solution will cause a delay in obtaining significant customer benefits. San Diego Gas & Electric indicated in its AMI project testimony that the utility will remain open to future changes should technologies emerge that present significantly superior AMI solutions to those currently planned and they are in the early stages of their commercial AMI rollout. Moving forward, it is important for the Hawaiian Electric Companies' to have a communications network that will cost-effectively support AMI and a Smart Grid. In addition, the Hawaiian Electric Companies plan to leverage mainland utilities' communication network planning activities, and interest to collaborate in this manner has been expressed by

[5] The powerline carrier system was called TWACS from DCSI.

several California utilities.

Q. Do you have any other comments on the Companies' consideration of possible AMI solutions?

A. The Consumer Advocate has expressed a concern about the Companies' focus on Sensus AMI technology and the fact that the evaluations of other AMI technologies were done a few years ago. In addition, the Consumer Advocate notes that the Companies' 2005 "high level" analysis of Broadband-Over Powerline ("BPL") technology indicated a breakeven period of seven to eight years but that no detailed business case analysis was completed, in spite of a longer (13- to 20-year) payback period for the proposed AMI Project.

BPL technology has enjoyed only limited commercial success and although the "high level" analysis (prepared by KEMA) indicated that the technology might have a six to seven year payback, the Hawaiian Electric Companies believe that this prediction was very optimistic and based on limited information, including the technical capabilities of BPL. Although a more detailed business case was not completed for BPL, the lack of commercial success indicates that this technology is no longer a major player in the AMI marketplace.

Q. Given the continued development and evolution of technologies and the magnitude of the expenditures associated with the proposed project, does the record in the instant proceeding convincingly support the proposed solution? How do you address the Consumer Advocate's assertion that regulators' ability to definitively determine that any proposed AMI solution is the optimal solution is inhibited by utility companies' inability to provide a comprehensive business case, including comparative analysis of various alternatives.

A. AMI technologies and products are rapidly evolving and utilities have more field experience with a variety of AMI products, both hardware and software, including rollouts at major utilities. The marketplace is competitive and further distinguished by AMI vendors who have collaborative relationships and ownership in DA companies. Notable players include Landis & Gyr, Silver Spring Networks, Elster, Itron, Trilliant Networks and Sensus. Two of these firms (Silver Spring and Trilliant) are exclusively communication network firms who are essentially meter agnostic and work in close partnership with most of the meter manufacturers.

Q. The Consumer Advocate has expressed a concern over the Companies' limited experience on Oahu with AMI technology. Are there measures in place to address this concern?

A. The performance level of the AMI system is embedded in the Service Level Requirements ("SLRs") of the Sensus Agreement, providing some level of risk mitigation. System Acceptance Testing ("SAT"), provided for in the Sensus Agreement, provides some additional risk mitigation coverage. However, the SAT involves a limited population of meters. After SAT testing is completed, incremental testing on fielded meters would need to continue occurring to ensure that AMI network performance meets the SLRs in the Sensus Agreement. If major coverage problems are encountered, the meter deployment will be halted until the problem(s) are resolved. From a hardware perspective, if AMI meter failure rates exceed 2.5% in a 12-month period during deployment, the Hawaiian Electric Companies will be released from their contractual requirement to purchase 90% of their AMI meters from Sensus.

Q. Are there any other concerns regarding the projected costs associated with the proposed project?

A. Yes. The Consumer Advocate contends that the Hawaiian Electric Companies' decision to abstain from using a bidding process does not cast a favorable light on the determination that the project costs are reasonable. The Hawaiian Electric Companies have provided substantial technical details and an AMI financial model which includes all the assumptions and cost estimates employed by the Hawaiian Electric Companies as well as the entire Sensus Agreement for review by the parties to this docket.

Q. Given the above, what is your recommendation regarding the need for the Commission to find that the project costs are reasonable?

A. As noted by the Consumer Advocate, the Companies prepared a detailed cost estimate based on available information and the executed Sensus Agreement, and developed B/C ratios to illustrate the extent to which the proposed AMI Project costs could be offset by quantifiable benefits. Some of these benefits reduce revenue requirements (i.e., meter reading, field services and meter capital savings) and others (i.e., meter accuracy gains and energy theft reductions) improve customer equity. Additional AMI benefits are described in Attachments 1 and 2 to the Companies' response to CA-IR-19.

The Hawaiian Electric Companies are aware that projects should be as cost-effective in order to provide value to their customers. As stated in the instant Application, the Companies proposed an AMI project which provides benefits which offset a significant portion of the costs of the project. B/C ratios were calculated to clearly indicate how the quantifiable benefits compared to the estimated project costs (see Mr. Hignite's testimony, HECO T-3). Benefits were restricted to those that were tangible and could be supported by available data and although the discounted B/C ratios indicate that costs exceed benefits, the Companies believe that future programs will provide other non-monetary benefits such as the increased utilization of renewable energy.

Q. Please discuss the Companies' proposal to recover costs from their customers based on the number of meters.

A. The Hawaiian Electric Companies have included estimated meter quantities, growth rates, and failure rates for each company's meter population in order to define meter costs. Other costs such as the MDMS costs are shared amongst the Hawaiian Electric Companies and allocated to each company based on customer counts as detailed in Mr. Hignite's testimony (HECO T-3). The AMI Project's incremental costs, net of benefits, are used to compute the incremental revenue requirements, which the Hawaiian Electric Companies propose to recover based on a per kWh surcharge based on forecasted sales for each company (see Exhibits 21 and 22 in the instant Application).

Q. Are there concerns by the other parties regarding cross subsidies amongst the three Hawaiian Electric Companies?

A. No. Page 42 of the Consumer Advocate's direct testimony supports the use of a relatively simple approach to cost allocation but expresses some concerns that arise when the AMI systems are integrated with OMS and CIS. Since the CIS is utilized by all three Companies, there is no Hawaiian Electric subsidy by MECO and HELCO. In contrast, integration with OMS is a concern of the Consumer Advocate due to the fact that HELCO and MECO do not have OMS systems yet. In the instant Application, the Hawaiian Electric Companies have not included any costs or benefits from integration with the OMS. The AMI system will provide the ability to interface and support the OMS. In its present form, all three Companies would be able to receive and display outage and restoration alarms through the AMI system's web-based front-end software. No integration with an OMS is required. Since Hawaiian Electric already has an OMS system, future integration with Hawaiian Electric's OMS would be logical but is outside the scope of the instant Application.

Q. Are the terms and conditions of the Sensus Agreement reasonable, prudent and in the public interest?

A. Yes. The Hawaiian Electric Companies endeavored to include favorable terms and conditions in the Sensus Agreement through a detailed negotiating process with Sensus. The reasonableness of the Sensus Agreement is reflected in CA-T-1 (pages 22-24), where the Consumer Advocate reiterates the various aspects of the Sensus Agreement and states that based on the review that the Consumer Advocate was able to conduct, the agreement appears to be generally reasonable. The relevant points in Exhibit 1 of the agreement are itemized by the Consumer Advocate as the basis for the determination that the agreement is reasonable.

Q. Did the other Parties have specific concerns about the Sensus Agreement?

A. Yes. Although the Consumer Advocate expressed that the Sensus Agreement generally appears reasonable, the Consumer Advocate had certain questions.

First, the Consumer Advocate noted that the integration of the Sensus-owned RNI is not an item contracted under the Sensus Agreement. This observation is correct. However, the estimated cost for integration (including contingency) of the RNI is included in the Hawaiian Electric Companies' financial model and has not been overlooked. The Companies plan to address integration in a separate contract with the AMI vendor or more likely, through the scope of work for the systems integrator. Mr. Hignite addresses integration costs and contingencies in HECO T-3.

Second, the Consumer Advocate noted a difference between the "guaranteed" AMI network coverage (93%) in Exhibit E of the Sensus Agreement and slightly higher coverage levels (95% for Hawaiian Electric and 96% for both MECO and HELCO) in Exhibit D of the Sensus Agreement. The Companies confirm that the AMI vendor only guarantees network coverage to 93% of the AMI meters. Additional coverage beyond 93% will increase the cost and number of network devices that would need to be installed by the AMI vendor and/or the Hawaiian Electric Companies. These devices include additional TGBs, FRPs, or FNPs.

AMI INTEGRATION WITH OTHER SYSTEMS

OMS

Q. Has the Consumer Advocate raised issues in this docket with respect to the OMS?

A. The Consumer Advocate expressed concerns about the OMS and potential conflicts and redundancies between AMI and the OMS. In regard to OMS integration, the instant Application indicated that the AMI system will support the OMS system but no costs or benefits have been assigned to OMS functionality in the instant Application. The current OMS system employs an Interactive Voice Recognition (IVR) system to partially automate outage reporting. The AMI meters have built-in outage and restoration alarm event capture and forwarding that can be integrated into the OMS at some future date. The AMI system can provide additional information that is not currently available through the OMS system and this can be useful, especially to MECO and HELCO, which do not currently have OMS systems. OMS integration is further discussed by Mr. Hignite in HECO T-3.

CIS

Q. Has the Consumer Advocate raised issues in this docket with respect to the CIS?

A. The Consumer Advocate expressed concerns about the CIS project and the interaction of the AMI with the CIS, given the current status of the CIS project. Details regarding CIS integration are provided by Mr. McMenamin in HECO T-4.

Q. Page 26 of the Consumer Advocate's testimony reiterates the Consumer Advocate's concern about interfacing to the CIS and the argument that the expected value of the AMI Project will be less than projected if this interface is not successfully implemented. How have these concerns been addressed?

A. In the near term, the delays in implementing a new CIS are not expected to impact the ability of the Hawaiian Electric Companies to achieve the savings associated with meter reading and field services labor reductions. The MDMS will be interfaced to the existing legacy CIS while new CIS options are designed and implemented. This issue is further addressed by Mr. McMenamin in HECO T-4. In addition, the benefits from improved meter accuracy will occur immediately upon installation of the AMI meters and the revenue protection module within the MDMS will support the reduction in electricity theft, as further discussed by Mr. Hignite in HECO T-3.

INFORMATION SECURITY

Q. How do the Hawaiian Electric Companies plan to protect customer related data?

A. In other dockets, the Consumer Advocate has discussed the need to take the appropriate measures to protect customer related data. The Consumer Advocate's testimony indicates that adequate measures are in place based on information presented by the Hawaiian Electric Companies in the instant Application. The Hawaiian Electric Companies participate in the Security Committee of the Utilities Telecom Council's Smart Networks Council (SNC) as well as the Sensus FlexNet Users Group Security Committee. In addition, the Companies have a dedicated Information Assurance (IA) Director who is tasked with developing cyber-security plans and addressing all matters in this subject area. The Hawaiian Electric Companies approach information security very seriously and significant efforts are underway in this regard.

CONCLUSION

Q. Could you please summarize your testimony?

A. The Hawaiian Electric Companies have proposed an AMI system that provides a platform for developing programs which give customers increased flexibility and satisfaction while empowering them to make wise energy choices, and also provides quantifiable operational benefits that offset project costs. Although the discounted B/C ratio is conservatively estimated at less than unity, indicating that the proposed AMI Project has costs exceeding its benefits, additional benefits that are more difficult to quantify can also be attributed to the AMI Project, particularly those that are generated by future programs that are yet to be implemented. Without AMI, these future programs will not materialize.

From a technology perspective, a rapid evolution is taking place. The

Hawaiian Electric Companies have started to develop Smart Grid roadmaps for each company and AMI will be an essential part of these roadmaps. From its initial inception, the AMI Project's potential has grown beyond simple metering to a foundational technology that supports the Smart Grid by providing data from nearly every one of the Hawaiian Electric Companies' customers and from the grid itself while enabling two-way communications that will be important for grid control functionality in the future.

The Consumer Advocate and other entities (Hawaii Renewable Energy Association, Hawaii Solar Energy Association, Life of the Land, and the National Regulatory Research Institute) have provided valuable comments and discussion on various aspects of the Hawaiian Electric Companies' proposed AMI Project, including the selection of an optimal AMI system and the realization that AMI is part of a "large Smart Grid construct" (see page 9 of HREA-T-1). The Smart Grid roadmap will take many years to navigate and the support of the Commission and the parties to this Docket is needed in order to achieve success.

Q. Does this conclude your testimony?

A. Yes it does.

HAWAIIAN ELECTRIC COMPANY, INC.

PAUL D. FETHERLAND

EDUCATIONAL BACKGROUND AND EXPERIENCE

BUSINESS ADDRESS:	Hawaiian Electric Company, Inc. P.O. Box 2750 Honolulu, Hawaii 96840
CURRENT POSITION:	Director, Advanced Metering Infrastructure System Integration Department
YEARS OF SERVICE:	15 Years
OTHER EXPERIENCE:	Director, Customer Technology Applications November 1992 – April 2006
EDUCATION:	MS (Electrical Engineering), University of California, Irvine BS (Chemical Engineering), University of Southern California

HECO T-3
DOCKET NO. 2008-0303

TESTIMONY OF
ANDY HIGNITE

PROJECT MANAGER
ADVANCED METERING INFRASTRUCTURE (AMI) DIVISION
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: AMI Project
Cost-Benefit Analysis

INTRODUCTION

Q. Please state your name and business address.

A. My name is Andy Hignite and my business address is 820 Ward Avenue, Honolulu, Hawaii.

Q. By whom are you employed and in what capacity?

A. I am the Advanced Metering Infrastructure ("AMI") Project Manager for Hawaiian Electric Company, Inc. ("Hawaiian Electric" or the "Company").

Q. Please state your professional experience and educational background.

A. My experience and educational background are provided in HECO-300.

Q. What is the scope of your testimony in this proceeding?

A. I will discuss the perspectives of Hawaiian Electric, Hawaii Electric Light Company, Inc. ("HELCO") and Maui Electric Company, Limited ("MECO") (collectively, the "Hawaiian Electric Companies" or "Companies") regarding the Cost-Benefit Analysis for the Companies' proposed AMI Project.

AMI MODEL

Q. How were the AMI Project costs and benefits estimated?

A. The Companies' cost estimates were developed by gathering and evaluating information from vendors, consultants, pending contracts and historical experience.

Q. How are the estimated costs and benefits documented and presented?

A. The estimated costs and benefits are documented within the AMI model, provided as Attachment 1 to the response to CA-IR-2 ("AMI Model"). The AMI

Model narrative, provided as Attachment 2 to the response to CA-IR-2 ("AMI Model Narrative"), explains the calculations within the AMI Model.

Q. What AMI Project benefits were identified and quantified for consideration in the AMI Model?

A. Table 12 of Attachment 1 to the Companies' response to CA-IR-35 presents all of the benefits that the Companies have been able to quantify. These quantifiable benefits are calculated within the AMI Model. The AMI Model and AMI Model Narrative present these benefits within the following sections:

Meter Hardware Benefits– Section VIII
(Includes Theft and Meter Accuracy Benefits)

Meter Reading Benefits – Section IX

Field Service Benefits – Section X

Ratepayer Benefits – Section XIII

It is expected that the AMI system will facilitate other benefits by providing a platform for additional technologies. However, the Companies are not able to specifically quantify other benefits at this time. For full realization of potential future benefits, additional investment will be required. As such, subsequent Commission applications would be required to address the potential costs and benefits of these investments.

Q. Can the parties evaluate the sensitivity and impacts in variations pertaining to the estimated costs, benefits and other assumptions for the AMI Project, to ensure that the risks of potential deviations are appropriately addressed?

A. Adjustments can be made to the input assumptions to perform sensitivity analyses within the AMI Model to ensure that the risks of potential deviations are appropriately addressed.

Q. Can adjustments to the input assumptions be made to the AMI Model as delivered in the response to CA-IR-2?

A. The AMI Model as delivered in the response to CA-IR-2 was an effort to enable the parties to this proceeding to fully review all aspects of the Companies' AMI Model. The AMI Model was delivered in "read only" mode to prevent an inadvertent alteration of the originally delivered file. The parties had full capability to open the AMI Model (using Microsoft Excel); view all portions of the file; make alterations as desired; and save the various scenarios to new files. In an effort to reduce the confusion that occurred by submitting the AMI Model in read-only format, the Companies will re-submit the AMI Model without limitations subject to the protective order filed April 15, 2009 within this docket.

PROJECT COSTS

Q. What is the estimated cost of the proposed AMI Project?

A. The updated total estimated AMI Project cost is $115 million. This total represents allocations to Hawaiian Electric, HELCO and MECO of $73.7, $22.2 and $19.1 million, respectively. The estimated costs are divided into four cost categories (Meter Data Management, AMI Network, AMI Meters and Project Management). A detailed allocation of the proposed costs was submitted in Tables 1 through 11 of Attachment 1 to the Companies' response to CA-IR-35 in the instant docket.

Q. Have any estimated costs changed within the AMI Model since the submittal of the Companies' response to CA-IR-35?

A. No. The estimated costs included in the AMI Model are the most current estimated costs.

Q. The project's cost has increased by approximately $5 million (to approximately $115 million) since the initial submittal of the Companies' AMI Application. Was this increase due to inaccuracies within the Companies' original assumptions?

A. No, the cost increase did not occur as a result of any inaccuracies within the Companies original assumptions. The AMI Project's cost increase of approximately $5 million is due mainly to the expansion of the project's proposed meter replacement (as explained in part d of the Companies' response to CA-IR-1). Other minor project changes were also implemented. All project changes are described in the Companies' response in this docket to CA-IR-35.

Q. Is there a risk that the AMI Project will actually end up costing more than $115 million?

A. As in any project, there is a risk of cost overruns with respect to the AMI Project. In order to prevent such potential overruns, the Companies performed considerable due diligence in establishing the project's cost estimates and performing risk mitigation. The AMI Model and the AMI Model Narrative detail and evaluate all estimated costs.

Q. Do the costs presented in the AMI Model represent the cost of an AMI system providing 100% network coverage?

A. No, the costs in the AMI Model only represent the costs associated with the Sensus contractual guarantee network coverage to 93% of the AMI meters. (Mr. Fetherland's testimony in HECO T-1 discusses AMI Network Coverage.)

Q. Did the Companies model additional costs specifically to cover potential problems with the network performance and coverage?

A. No. As described in the Companies' response to CA-IR-16, part d.2., the Companies selected an operating lease for the AMI Network. This approach mitigates the Companies' risk with respect to network performance and coverage.

Q. Did the Companies model any other costs which may have not been directly recognized and/or quantified with the AMI Model?

A. Yes, the Companies included a "General Contingency" cost multiplier of 10% within the AMI Model costs.

Q. Did the Companies attribute a higher level of risk to the Meter Data Management System ("MDMS") than to the rest of the AMI Project?

A. Yes. Even with the diligence that the Companies put into the MDMS cost estimate, the Companies expect that the selection, development and implementation of the MDMS will be the highest potential risk component of the AMI Project.

Q. Was this 10% general contingency applied to all estimated costs?

A. No. The Companies assumed that the MDMS would entail a higher risk of cost overruns; therefore, the 10% general contingency was not applied to the MDMS estimated costs.

Q. Did the Companies take any affirmative action within the MDMS cost estimate to mitigate these expected higher risks pertaining to the implementation of the MDMS?

A. Yes, the Companies replaced the General Contingency (10%) multiplier with a "Higher Level Contingency" (20%) multiplier for all the estimated MDMS costs.

Q. Since the MDMS and its vendor have not yet been selected, is it possible that the costs will increase due to conditions that place upward pressure on the final cost of the MDMS? Is it possible that a vendor might quote a lower price in order to secure a contract, but then, through subsequent change orders or other means, increase the cost such that the final cost of the AMI Project will be higher than projected?

A. The Companies plan to control these risks by performing a comprehensive MDMS vendor RFP process. The MDMS RFP will identify all of the Companies' MDMS requirements. Efforts will be taken in the development of the RFP, selection of the systems and consultants, and in the management of the development and implementation to minimize changes in scope, which could lead to cost overruns.

Q. How accurate are the Companies' MDMS cost estimates?

A. In recognition of the Companies' limited experience in estimating MDMS cost assumptions, the Companies utilized a number of resources to maximize the accuracy of their assumptions. The following resources were utilized in the development of these assumptions:

- Hawaiian Electric's Information Technology & Services ("ITS");
- an experienced MDMS expert consultant (Enspiria Solutions);
- the Hawaiian Electric Companies' Customer Information System ("CIS") integrator (Bass); and
- input from a typical MDMS vendor (Itron).

The Companies utilized an iterative process to assemble input from all these sources into a comprehensive cost estimate. The result of the estimate is presented within Section V of the AMI Model.

Q. How were the MDMS cost estimates classified?

A. The MDMS is classified as a major software development project in excess of $500,000. Accordingly, the MDMS costs were classified per the "Accounting for the Costs of Computer Software Developed or Obtained for Internal Use" memo as Expensed, Deferred or Capitalized. The breakdown of these estimated costs is presented in Section V of the AMI Model. The AMI Model Narrative explains the breakdown of these estimated costs and the related MDMS calculations.

Q. Could there be other costs that may not have been quantified?

A. Considerable time was expended in developing the AMI Model and AMI Model Narrative in order to identify, quantify and document all significant AMI Project expenses. As in any model, there may be additional costs that have not been addressed explicitly in the AMI Model.

Q. If it is impractical to expect that every cost can be specifically identified, how were potentially unidentified costs addressed?

A. To address costs that may have not been specifically recognized within the AMI Model, the Companies applied a contingency cost premium (general contingency or high level contingency) on all of the estimated costs. The applications of the contingency costs are described above.

COST IMPACTS OF SYSTEMS INTEGRATION

Q. Do the Companies plan to use a System Integrator ("SI") for the MDMS project?

A. Yes.

Q. How did the Companies develop the cost estimations for the SI?

A. The cost estimations for the SI were developed within the same iterative process that was used to develop all the estimated MDMS costs.

Q. Has the SI been selected?

A. No.

Q. What process will be utilized to select the SI?

A. The SI will be selected using the same RFP process used to select the MDMS vendor and system.

Q. How are concerns of potential costs overruns related to the SI addressed?

A. The RFP process will attempt to clearly identify the full scope of the SI's responsibility. Even with this level of diligence, it is possible that a scope change could be required which could potentially increase the cost of the SI. To mitigate this risk, the Companies included a 25% risk premium on all the estimated SI costs.

Q. Are there certain benefits to the proposed AMI system that can only be achieved with the successful interface with other systems, such as the CIS? Without those other systems in place or interfaces that work correctly, is the expected value of the AMI project will be less than projected?

A. The interfacing of the Regional Network Interface ("RNI") and the MDMS is critical to the implementation of the AMI Project. As a result, all of the interfacing efforts have been estimated within the AMI Model and these costs are detailed in Section V of the AMI Model and the AMI Model Narrative. The AMI system must be integrated with an operational CIS to fully realize the AMI Project's quantified benefits. Integration with the Companies' current CIS (CB-ACCESS) can achieve all of the AMI Project's currently quantified benefits without reducing the quantified expected value of the AMI Project. Additional interfacing and CIS capabilities may be required to fully achieve all potential future benefits. (Mr. McMenamin provides further clarification pertaining to the integration plan and options in HECO T-4.)

Q. Is it possible that additional costs might be incurred to integrate Hawaiian Electric's OMS with the AMI system?

A. As noted in the Companies' response to CA-IR-13, part c, the Sensus FlexNet System and the MDMS software products continue to evolve and current OMS support is limited. Custom interfaces will be required to fully achieve the desired AMI/OMS synergy. Hawaiian Electric's current OMS version is not fully AMI-compliant; therefore, an OMS upgrade may be required to fully achieve the potential AMI/OMS benefits. Further evaluation is required to fully quantify the costs, benefits and risks associated with the AMI system's support of the OMS. As a result, there would be additional costs incurred to integrate Hawaiian Electric's OMS with the AMI system.

Q. Is recovery of the additional OMS-AMI integration costs being requested under the Companies' Application in this docket?

A. No. The additional costs that would be incurred to integrate Hawaiian Electric's OMS with the AMI system are not requested under the Companies' Application in this docket. Further planning and analysis is required to ensure that the costs and benefits justify the integration of the AMI system with the OMS. If the Companies determine that the integration of Hawaiian Electric's OMS with the AMI system is justified, a separate application for those activities will be filed.

Q. Would costs pertaining to the integration of the Hawaiian Electric's OMS with the AMI system be allocated to HELCO's or MECO's customers?

A. The Companies do not expect that integration of Hawaiian Electric's OMS with the AMI system would provide any benefits to HELCO's or MECO's customers. As such, it is not expected that any of those potential future costs would be allocated to those customers.

Q. Is it possible that the AMI system and the OMS might provide redundant functions?

A. As explained in part a of the Companies' response to CA-IR-13, the OMS tracks, records and reports metrics on all phases of an outage. An AMI system and the OMS do not have redundant functions. Rather, an AMI system enhances the capability of the OMS by providing quicker and more accurate information delivery and access.

Q. Is it possible that the AMI system and the OMS might not be able to interface and work in a synergistic fashion?

A. It is anticipated that the OMS and AMI system can work together in a synergistic fashion and provide additional functionality that exceeds the present capabilities of the OMS.

AMI BENEFITS

Q. What are the estimated quantified benefits of the proposed AMI Project during the proposed period of deployment (2010-2015)?

A. The updated estimate of the AMI Project's total quantifiable benefits is $36.0 million during the proposed period of deployment (2010-2015). This total represents estimated quantifiable benefits to Hawaiian Electric, HELCO and

MECO of $31.0, $1.6 and $3.4 million, respectively. The estimated quantifiable benefits are divided into five categories (Meter Reading Savings, Field Service Savings, Theft of Electricity Savings, Accuracy of Meter Savings and Meter Capital Savings). A detailed allocation of the estimated, quantifiable benefits was submitted in Table 12 of Attachment 1 to the Companies' response to CA-IR-35.

Q. Do the estimated, quantified benefits of the proposed AMI Project of $36.0 million represent all of the quantified benefits expected to be realized over the life of the Companies' AMI system?

A. No, the estimated quantified benefits of $36.0 million for the AMI project only represent the quantified benefits expected to be realized through the implementation of the project (2010 through 2015). It is estimated that the final phase of the project implementation (HELCO's meter installation) will be completed by the end of 2015.

Q. Will the quantifiable AMI benefits continue beyond the end of the AMI Project's implementation?

A. Yes. The quantifiable AMI benefits will continue beyond the end of the project's implementation.

Q. What are the estimated quantifiable benefits of the AMI Project for the 20-year period from 2010 through 2029?

A. The AMI Project's total 20-year quantifiable benefits (2010 through 2029) amount to $278 million. This total represents estimated quantifiable benefits to

Hawaiian Electric, HELCO and MECO of $183.8, $48.1 and $46.1 million, respectively. Over this same time period, the estimated project costs amount to $222.5 million. This total represents estimated project costs to Hawaiian Electric, HELCO and MECO of $133.1, $48.7 and $40.6 million, respectively.

Q. Have any estimated benefits changed within the AMI Model since its submittal response to CA-IR-2?

A. No. The estimated benefits included in the AMI Model as submitted within the response to CA-IR-2 are the most current estimated costs.

Q. Did the Companies estimate benefits due to meter accuracy gains?

A. Yes. The Companies' estimated that there would be meter accuracy gains equal to approximately 0.4% of the Companies' residential sales. Section VIII.D.1.b of the instant Application describes the Companies' anticipated benefits attributable to the persistent accuracy of the AMI meters

Q. Are the underlying assumptions related to the average level of inaccurate readings per meter being skewed towards slow meters justified?

A. Yes. Exhibit 16 of the instant Application describes the Companies' anticipated benefits attributable to the meter accuracy gains. The Companies performed a detailed analysis and testing of approximately 500 meters within their service territories. The analysis compared the accuracy of the new AMI meters with the accuracy of the Companies' current meter base.

Q. Are the estimated quantified benefits related to meter accuracy gains achievable without the CIS that is the subject of Docket No. 04-0268 without additional work?

A. Yes. Meter Accuracy benefits will be immediately recognized upon the replacement of the old meters with the new AMI meters. This benefit can be realized without the CIS. All estimated costs pertaining to achieving the meter accuracy gains are included within the Companies' Application in this docket.

Q. How were the estimated benefits pertaining to the meter accuracy gains calculated?

A. Section XI.C of the AMI Model and the AMI Model Narrative document and describe the assumptions and calculations pertaining to the meter accuracy gains.

Q. Did the Companies estimate an increase in energy theft recovery?

A. Yes. The Companies' estimated that there would be an increase in energy theft recovery equal to approximately 0.14% of the revenues recorded by the replaced meters. Section VIII.D.1.c of the instant Application describes the Companies' anticipated benefits attributable to the greater energy theft recovery.

Q. Is the basis for the belief that such levels of energy theft to exist in Hawaii justified?

A. Energy theft occurs in Hawaii, as in other locations. The Companies utilized the best available information to formulate the estimated energy theft basis within their territories. The worksheet showing the calculation for the Companies' energy theft basis was provided as Exhibit 17 to the instant Application. The

Companies have no available information indicating that energy theft basis in Hawaii differs from the theft basis represented in their estimate.

Q. Are the estimated quantified benefits related to energy theft recovery achievable without the CIS that is the subject of Docket No. 04-0268 without additional work?

A. Yes. Improved energy theft recovery will be enabled by the new MDMS as soon as the new AMI meters are installed and the Phase I of the MDMS installation is complete. AMI meters automatically transmit power failure and tamper alarms to the MDMS for analysis. The MDMS will be able to independently perform advanced energy theft detection without any additional assistance from the CIS. This benefit can be realized without the CIS. All estimated costs pertaining to achieving the meter accuracy gains are included within the Companies' Application in this docket.

Q. How were the estimated benefits pertaining to the energy theft recovery gains calculated?

A. Section XI.D.1 of the AMI Model and the AMI Model Narrative document and describe the assumptions and calculations pertaining to the energy theft recovery.

Q. The Companies state that the AMI Project will result in meter capital savings. Is the characterization of the estimated meter capital savings as savings correct?

A. Yes. The meter capital savings represent estimated meter capital hardware purchases and installation costs that would be incurred in the normal operation and maintenance of the system in the absence of full deployment of the AMI meters. These normal meter exchanges include replacement of failed meters and new meter installations. New meters are typically installed for new customers and existing customers with new, special metering requirements such as time-of-use or net energy metering requirements.

Q. How were the estimated meter capital savings calculated?

A. Section VIII of the AMI Model and the AMI Model Narrative document and describe the assumptions and calculations pertaining to the meter capital savings.

Q. Did the Companies conduct scenario analyses that included the cost differential between the purchase and installation of AMI and non-AMI meters in that type of model?

A. No. The full cost of the AMI meters is already recognized within the deployment costs of the new meters. This savings estimate does not compare the costs associated with the installation of an individual AMI meter against the cost associated with the installation of an individual non-AMI meter. Rather, it represents non-AMI meter costs that will be avoided as a result of the implementation of the AMI Project. Section II of the AMI Model and the AMI Model Narrative document and describe the AMI meter installation costs.

Q. Did the Companies estimate that there would be benefits due to savings in meter reading costs?

A. Yes. The Companies estimated that there would be benefits due to savings in meter reading costs. Section VIII.D.1.a of the instant Application and the

Companies' response to CA-IR-6 describe the Companies' anticipated benefits due to savings in meter reading costs.

Q. Did the Companies anticipate a reduction in the meter reader head count?

A. Yes. The anticipated reductions in the meter reader head count for HECO, HELCO and MECO are 26, 8 and 6, respectively. Attachment 1 to the response to CA-IR-6 shows this anticipated meter reader head count reduction.

Q. How were the estimated benefits due to savings in meter reading costs calculated?

A. Section IX of the AMI Model and the AMI Model narrative document and describe the assumptions and calculations pertaining to the estimated benefits due to savings in meter reading costs.

Q. Did the Companies estimate that there would be benefits due to savings in field service costs?

A. Yes. The Companies' estimated that there would be benefits due to savings in field service costs. Section VIII.D.1.a of the instant Application and the response to CA-IR-5 describe the Companies' anticipated benefits due to savings in field service costs.

Q. Did the Companies anticipate a reduction in the field service head count?

A. Yes. The anticipated reductions in the field service head count for HECO, HELCO and MECO are 8, 4 and 2, respectively. Section X.E.3 of the AMI Model shows this anticipated meter field service head count reduction.

Q. How were the estimated benefits due to savings in field service costs calculated?

A. Section X of the AMI Model and the AMI Model Narrative document and describe the assumptions and calculations pertaining to the estimated benefits due to savings in field service costs.

BENEFIT-COST RATIO

Q. What are the estimated payback period and the discounted and non-discounted benefits-to-cost ("B/C") ratios for the proposed AMI Project?

A. The Companies' computed discounted and non-discounted B/C Ratios for the AMI Project are provided in the table below. The simple payback periods for Hawaiian Electric, MECO, and HELCO are estimated to be 13, 17 and 20 years, respectively. Future programs that are enabled by AMI such as Demand Response will improve these estimated B/C ratios.

	(1) AMI Benefit Cost Evaluation	
	(2) B/C Ratio Discounted	(2) B/C Ratio Non-Discounted
Hawaiian Electric	(3) 0.94	1.42
HELCO	(3) 0.71	1.00
MECO	(3) 0.81	1.17

(1) B/C Ratio Analysis using the Estimated Costs and the Estimated Quantifiable Benefits for the AMI Project for the years 2010 through 2029 from the AMI Model.

(2) A discount rate of 8.62% was used for this analysis.

(3) AMI Model, Section XIII.D.3.

Q. Does Attachment 1 to the Companies' response to CA-IR-3 to this docket contain a typographical error listing two B/C Ratio entries for HELCO and no entry for MECO?

A. Yes. The corrected table is shown above.

Q. In the Companies' response in this docket to CA-IR-3, the B/C information listed within part a. of the response did not match the information contained in Attachment 1 to the response. Is the B/C information listed within part a. of the Companies' response in this docket to CA-IR-3 correct?

A. No. The B/C information listed within the part a. of that response was incorrect. The information contained within the Attachment 1 of the response was correct (with the exception of the typographical error noted above). The information listed within the part a. should have stated:

> *The Companies' estimate of quantifiable costs and benefits indicate that the AMI Project has a non-discounted Benefit/Cost Ratio of 1.42 for HECO, 1.17 for MECO, and 1.00 for HELCO. ... The Companies' estimate of quantifiable costs and benefits indicate that the AMI Project has a discounted Benefit/Cost Ratio of 0.94 for HECO, 0.81 for MECO, and 0.71 for HELCO.*

SUMMARY

Q. Please summarize your testimony.

A. The Companies developed and presented a detailed AMI Model in the instant Application to illustrate the relative viability of the AMI Project, using estimates of costs and quantifiable benefits. Additional benefits have not been quantified; however, additional intangible benefits that have not been quantified are expected to occur in the future due to implementation of the AMI Project.

Q. Does this conclude your testimony?
A. Yes it does.

HAWAIIAN ELECTRIC COMPANY, INC.

ANDY L. HIGNITE

EDUCATIONAL BACKGROUND AND EXPERIENCE

BUSINESS ADDRESS:	Hawaiian Electric Company, Inc. P.O. Box 2750 Honolulu, Hawaii 96840
CURRENT POSITION:	Project Manager, Advanced Metering Infrastructure Division System Integration Department
YEARS OF SERVICE:	5 Years
OTHER EXPERIENCE:	Advanced Metering Infrastructure System Administrator, Customer Service Division, Customer Installations Department Outage Management System Analyst, Finance & Administration Division, Information Technology & Services Department Energy Management System Analyst, Energy Delivery Division, System Operation Department Plant Engineer, AES Hawaii, Inc. Chief Petty Officer, United States Navy
EDUCATION:	MSIS, Hawaii Pacific University, Honolulu, HI BSCS, Hawaii Pacific University, Honolulu, HI

ACCOUNTING FOR THE COSTS OF COMPUTER SOFTWARE DEVELOPED OR OBTAINED FOR INTERNAL USE

(Updated as of April 1, 2006)

Introduction
The following guidelines are provided to assist in the accounting for computer hardware and software costs (acquired, internally developed, or modified solely to meet the entity's needs). This is not meant to be all-inclusive, however we will continue to add or revise the information below, as needed, to provide additional clarification. Questions with respect to these guidelines should be addressed to the Controller or Director of Corporate and Property Accounting.

As a general rule, the costs of computer software, including applicable labor to install the software, and ongoing maintenance are generally charged to the appropriate functional operation and maintenance (O&M) expense account(s), i.e. expensed as incurred, based on the benefiting organization unless:

1. Deferrable software costs have been identified in accordance with applicable accounting standards AND approval has been obtained from the PUC allowing the Company to defer those costs,
2. The computer software is an operating system-type (e.g., Windows XP) software needed to render the new computer hardware "used or useful",
3. Specific overhead costs allowed to be applied to deferrable software costs,
4. AFUDC on deferrable software costs.

Costs for software development projects less than $500K would generally be expensed as incurred. (The $500K threshold refers to the amount of costs that would be deferred during the application development stage described below. It does not refer to the total costs that would be incurred during all three project stages described below.) Please notify the Controller or Director of Corporate and Property Accounting of projects that are less than $500K that will be expensed.

Accounting for Computer Software Guidelines
The costs of software upgrades and enhancements that do not provide additional functionality to the existing software (i.e., modifications to the existing software that would enable the software to perform tasks that it was previously incapable of performing) should be charged to the appropriate functional O&M expense account(s), i.e. expensed as incurred, based on the benefiting organization.

Software that is acquired, internally developed, or modified solely to meet the entity's needs should adhere to the guidance set forth below. In general, software development can be segregated into three stages as follows (also summarized in Exhibit 1):

- Preliminary Project Stage. This stage includes conceptual formulation of software alternatives, evaluation of the alternatives, determination of the existence of needed technology, and final selection of alternatives. Internal and external costs incurred during this stage should be charged as incurred to the appropriate functional O&M expense account(s), based on the benefiting organization, i.e. expensed as incurred.

- Application Development Stage. This stage includes the design of a chosen path, including software configuration and software interface, coding, software installation, and testing, including parallel processing. Certain internal and external costs incurred during this stage should be deferred, including costs to develop or obtain software that allows for access of old data by new systems. Certain applicable overhead and AFUDC costs on the deferrable software costs is also deferred.

  The process of data conversion from old to new systems may include purging or cleansing of existing data, reconciliation or balancing of the old data and the old/new system, creation of new/additional data, and conversion of old data to the new system. Data conversion often occurs during the Application Development Stage; however, data conversion costs, other

ACCOUNTING FOR THE COSTS OF COMPUTER SOFTWARE DEVELOPED OR OBTAINED FOR INTERNAL USE

(Updated as of April 1, 2006)

than the costs to develop or obtain software that allows for access of old data by new systems, should be charged as incurred to the appropriate functional O&M expense account(s), based on the benefiting organization, i.e. expensed as incurred.

- Post-Implementation/Operation Stage. This stage includes training and application maintenance. Internal and external costs incurred during this stage should be charged as *incurred to the appropriate functional O&M expense account(s), based on the benefiting* organization, i.e. expensed as incurred.

Further, costs of activities typically associated with business process reengineering should be charged as incurred to the appropriate functional O&M expense account(s), based on the benefiting organization, i.e. expensed as incurred. Note that these activities can occur during any stage above. Examples include the following:

- Preparation of a request for proposal
- Current state assessment – The process of documenting the entity's current business process, except as it relates to current software structure. Often referred to as *mapping, developing an "as-is" baseline, flow charting,* and *determining current business process structure.*
- Process reengineering – The effort to reengineer the entity's business process to increase efficiency and effectiveness. This activity is sometimes referred to as *analysis, determining "best-in-class," profit/performance improvement development,* and *developing "should-be" processes.*
- Restructuring the work force – The effort to determine what employee is necessary.

Accounting for Computer Hardware Guidelines:
Any computer hardware costs incurred relative to the development or acquisition of software should be capitalized following existing Company policies and procedures. Computer operating system software which is acquired in connection with new hardware should be capitalized together with the hardware under the basis that the operating system is needed to deem the hardware "used or useful".

ACCOUNTING FOR THE COSTS OF COMPUTER SOFTWARE DEVELOPED OR OBTAINED FOR INTERNAL USE

(Updated as of April 1, 2006)

Exhibit 1

The following table sets forth the accounting for typical components of a software development project based on whether the item should be expensed, deferred, or capitalized. Please note that some of the activities listed below may occur in multiple stages.

	Internal or Third Party		
Steps	**Expensed**	**Deferred**	**Capitalized**
Business process reengineering and information technology transformation (these activities primarily occur, but not limited to, prior to preliminary project stage):			
Preparation of request for proposal (RFP)	X		
Current state assessment (*i.e., mapping, developing an "as-is" baseline, flow charting, determining current business process structure.*)	X		
Process reengineering (*i.e., analysis, determining "best-in-class," profit/ performance improvement development, developing "should-be" processes.*)	X		
Restructuring work force	X		
Preliminary software project stage activities:			
Conceptual formulation of alternatives	X		
Evaluation of alternatives	X		
Determination of existence of needed technology	X		
Final selection of alternatives	X		
Examples of the preliminary project stage include: • Strategic decisions to allocate resources between alternative projects at a given point in time (e.g., should programmers develop a new payroll system or direct their efforts toward correcting existing problems in an operating payroll system?) • Determine the performance requirements (i.e., what the software needs to do) and systems requirements for the project • Invite vendors to perform demonstrations of how their software will fulfill an entity's needs • Explore alternative means of achieving specified performance requirements (e.g., should an entity	X		

ACCOUNTING FOR THE COSTS OF COMPUTER SOFTWARE DEVELOPED OR OBTAINED FOR INTERNAL USE

(Updated as of April 1, 2006)

	Internal or Third Party		
Steps	**Expensed**	**Deferred**	**Capitalized**
make or buy the software? Should the software run on a mainframe or a client server system?) • Determine that the technology needed to achieve performance requirements exists • Select a vendor if an entity chooses to obtain software • Select a consultant to assist in the development or installation of the software			
Application development stage activities:			
Design of chosen path, including software configuration and software interface		X	
Coding		X	
Installation to hardware		X	
Testing, including parallel processing phase		X	
Data conversion costs: a. Costs to develop or obtain software that allows for access of old data by new system		X	
b. Process of converting data from old to new systems (e.g., purging or cleansing of existing data), reconciliation or balancing of the old data and the new data in the new system, creation of new/additional data, and conversion of the old data to the new system.	X		
Training	X		
Post-implementation/ operation stage activities:			
Training	X		
Application maintenance	X		
Ongoing support	X		
Acquisition of fixed assets:			
Purchase of hardware, office furniture, or work stations, including operating system			X
Reconfiguration of work area - architect fees and hard construction costs			X

HECO T-4
DOCKET NO. 2008-0303

TESTIMONY OF
STEVE MCMENAMIN

ACTING CHIEF INFORMATION OFFICER
INFORMATION TECHNOLOGY SERVICES
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Integration of Meter Data Management System (MDMS) and Customer Information System (CIS)

INTRODUCTION

Q. Please state your name and business address.

A. My name is Steve McMenamin and my business address is 900 Richards Street, Honolulu, Hawaii.

Q. By whom are you employed and in what capacity?

A. I am the acting Chief Information Officer of Hawaiian Electric Company, Inc. ("Hawaiian Electric" or the "Company"). My experience and educational background are listed in HECO-400.

Q. What is your area of responsibility in this testimony?

A. My testimony will cover the integration of the Meter Data Management System ("MDMS") and the Customer Information System ("CIS").

Q. Can you please outline your testimony?

A. This testimony will cover the general approach to integration, and the concerns raised by the Consumer Advocate.

GENERAL APROACH TO INTEGRATION

Q. What is the general process to connect the MDMS to the CIS?

A. Because the implementation of Hawaiian Electric's new CIS has taken longer than originally envisioned, the Company has decided to divide the work of integrating the MDMS with the Company's customer systems into three phases. The three phases of the MDMS implementation are described on page 4 of Exhibit 9 of Hawaiian Electric, Hawaii Electric Light Company, Inc. ("HELCO") and Maui Electric Company, Limited's ("MECO") (collectively, the "Hawaiian Electric Companies" or "Companies") Application in Docket No. 2008-0303 for approval of their Advanced Metering Infrastructure ("AMI") Project. The MDMS

Architecture from page 2 of Exhibit 9 is attached in exhibit HECO-401 to this testimony.

Q. Why has Hawaiian Electric selected this phased approach?

A. The phased approach will allow quicker realization some important benefits of the AMI Project even while the Company is still using its legacy CIS. For example, by linking the MDMS system to the legacy CIS using the connection point currently employed by the Company's Multi Vendor Reading System ("MVRS"), Hawaiian Electric will be able to achieve cost savings in meter reading operations right away. Once the new CIS is complete, the Company will be able to achieve additional benefits associated with advanced metering capabilities.

<u>CONSUMER ADVOCATE CONCERNS</u>

Q. Given the concerns expressed by the Consumer Advocate about the cost to interconnect to both the existing and new CIS (see CA-T-1, pages 46 and 47), how will these costs be managed?

A. Hawaiian Electric will design the interfaces to its legacy CIS with the knowledge that it will be supplanted at some point by the interface to the new CIS. The Company will, to the best of its ability, anticipate the requirements of the later interface in the design of the initial interface in Phase I. By doing so, Hawaiian Electric will minimize rework in the subsequent phases, thereby minimizing additional cost.

Q. When will the benefits of Time-of-Use and Dynamic Rates be realized?

A. As described on Page 2, Exhibit 25 of the Companies' AMI Application, these benefits will be realized with the implementation of the new CIS. As of this time, Hawaiian Electric has yet to establish a schedule for the implementation of the new CIS.

SUMMARY

Q. Please summarize your testimony.

A. Hawaiian Electric plans to initially interface the MDMS with the Company's legacy CIS, and ultimately with the new CIS. This approach will enable the Company to realize many of the claimed benefits of automated meter reading immediately. Some other benefits will not be realized until the new CIS is completed. Because the Company going into this effort will have the knowledge that it will need to adapt the interfaces to the new CIS, Hawaiian Electric will design the interfaces with this transition in mind to control costs.

Q. Does this conclude your testimony?

A. Yes, it does.

HAWAIIAN ELECTRIC COMPANY, INC.

STEPHEN M. McMENAMIN

EDUCATIONAL BACKGROUND AND EXPERIENCE

Business Address:	Hawaiian Electric Company, Inc. 900 Richards Street Honolulu, HI 96813	
Position:	Acting Chief Information Officer	
Years of Service:	Less than 1	
Education:	Cornell University, Ithaca, New York	
Previous Positions:	2006-2009	Borland Software Corp. Vice President, Engineering Santa Ana, California
	2001-2005	BEA Systems, Inc. Vice President, Engineering Kirkland, Washington
	2000	Edison International Vice President, eCommerce Rosemead, California
	1997-1999	Southern California Edison Division Vice President, Business Process Integration Rosemead, California
	1993-1997	Southern California Edison Division Vice President, Customer Service Rosemead, California
	1987-1993	Southern California Edison Various Management Positions Rosemead, California

Previous Positions: (continued)	1983-1987	Founder and Principal The Atlantic Systems Guild, Inc. New York, New York
	1977-1983	Consultant and Fellow Yourdon, Inc. New York, New York

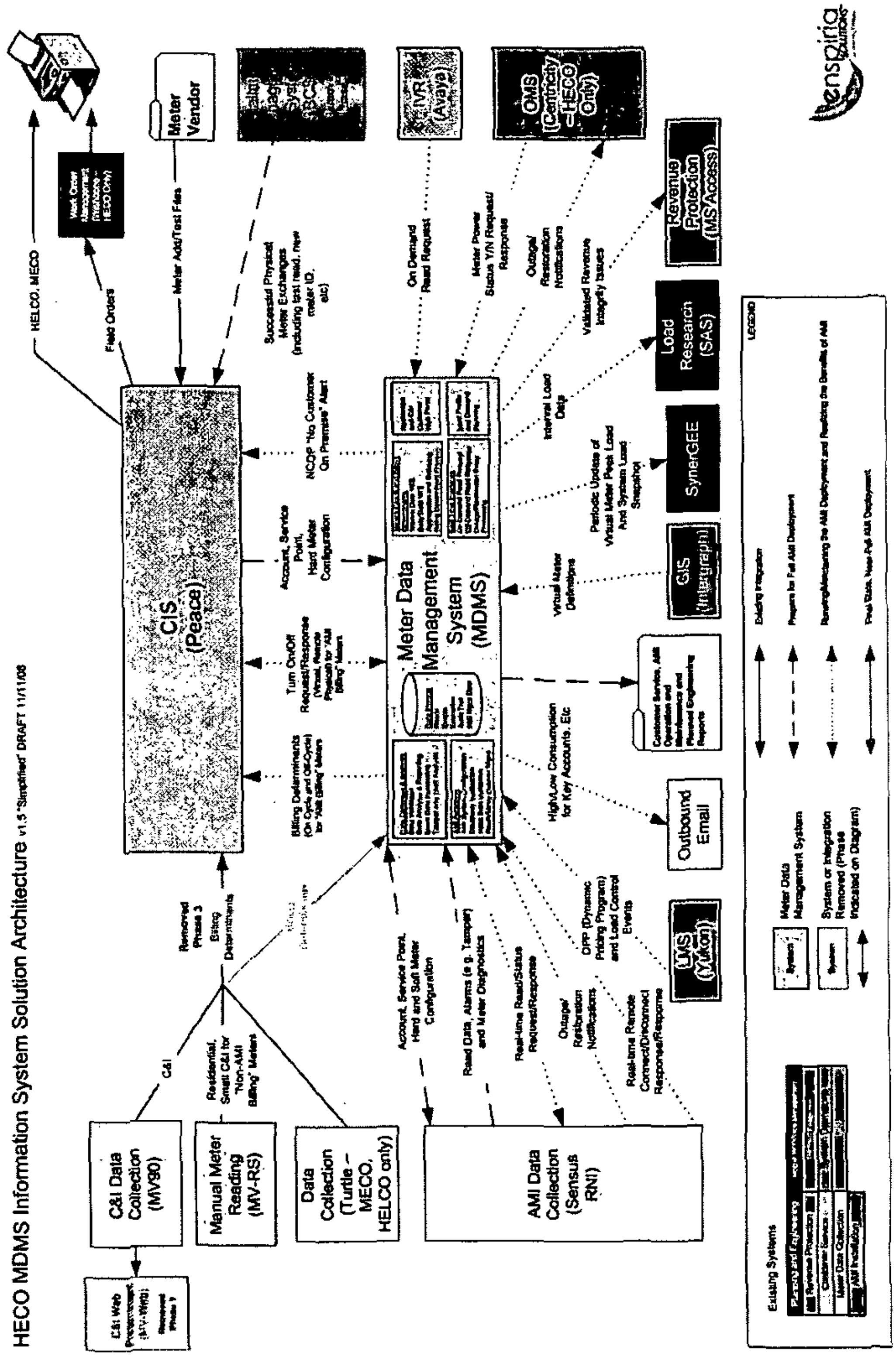


Figure 1 – MDMS Architecture

TESTIMONY OF
PATSY H. NANBU

CONTROLLER
GENERAL ACCOUNTING DEPARTMENT
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Accounting and Ratemaking Treatment for the New AMI Meters, Existing Non-AMI Meters AMI Network Lease expense, and Meter Data Management System Software Development Costs

INTRODUCTION

Q. Please state your name and business address.

A. My name is Patsy H. Nanbu and my business address is 900 Richards Street, Honolulu, Hawaii.

Q. What is your present position?

A. I am the Controller for Hawaiian Electric Company, Inc. ("Hawaiian Electric"). My educational background and experience are listed in HECO-500.

Q. What is your area of responsibility in this proceeding?

A. I will describe the accounting and proposed ratemaking treatment for the following components of the Advanced Metering Infrastructure ("AMI") Project proposed by Hawaiian Electric, Hawaii Electric Light Company, Inc. ("HELCO") and Maui Electric Company, Limited ("MECO") (collectively, the "Hawaiian Electric Companies" or "Companies"): 1) new AMI meters; 2) existing non-AMI meters; and 3) Meter Data Management System ("MDMS") software development costs. I will also describe the surcharge cost recovery of the net incremental costs of the AMI Project.

NEW AMI METERS

Q. What is the Companies' overall position with respect to the accounting and proposed ratemaking treatment for the new AMI meters?

A. The Companies' position is that investment in the new AMI meters as part of the overall AMI Project is reasonable to meet the objectives of the AMI Project and is in the public interest. The costs of such prudently incurred costs for this project should be recoverable from ratepayers.

Q. Has the Companies' position changed from what was presented in the AMI Project Application?

A. No. The Companies' position has not changed.

Q. How do the Hawaiian Electric Companies propose to account for the costs of the new AMI meters?

A. The Companies propose to capitalize the installed costs of the new AMI meters upon installation and include the meters as utility assets. The Companies will depreciate the new AMI meters over the current Commission approved depreciation rates for meters, beginning January 1 of the year following the placement of the meters into service. This accounting is consistent with any other capital expenditure project undertaken in the normal course of business.

Q. How do the Companies propose to recover the costs of the new AMI meters?

A. For ratemaking purposes and for purposes of calculating the revenue requirements for inclusion in the Renewable Energy Infrastructure Program ("REIP") or AMI surcharge, the Companies propose to include the new AMI meters as utility assets in rate base and to recover the investment on a straight-line basis over a period of seven years from installation. This represents an accelerated recovery of the Companies' investment in these new AMI meters.

Q. What is the Consumer Advocate's position with respect to the Companies' accounting and proposed ratemaking treatment for the new AMI meters?

A. The Consumer Advocate's witness Mr. Nishina, in CA-T-1, pages 36-37, expressed concern with the accelerated recovery of the Companies' investment in the new AMI meters and recommended that the Commission not approve the accelerated recovery request.

Q. What are the Consumer Advocate's concerns?

A. The Consumer Advocate has expressed concerns that: 1) it has not received information from the credit rating agencies supporting the Hawaiian Electric Companies' assertion that the Companies' credit rating will be negatively impacted without approval of the accelerated recovery; 2) the requested accelerated recovery is not entirely consistent with the Energy Agreement; and 3) there is a difference in the seven-year accelerated recovery period and the longer book depreciation period. Ms. Sekimura, in HECO T-6, discusses the needed for accelerated cost recovery of the new AMI meters.

Q. How did the Hawaiian Electric Companies determine proposing to recover the costs of the new AMI meters over a seven-year period?

A. As described in the Companies' response to PUC-IR-8, the Companies evaluated several scenarios with different recovery periods. The impact on the Companies' budget and financing plan, as well as the potential impact on ratepayers, was considered. A seven-year recovery period was found to be a period of time which would provide the Companies a reasonable opportunity to recover their investment in a timely manner, provide cashflow to support other investment in the later years of the project, and also fit the Companies' future financing plans. This seven-year period would also help smooth out the revenue requirement and lessen the impact to ratepayers in any single year (as compared to a shorter recovery period), while at the same time, providing the Companies an opportunity to recover their investment in a more timely manner so as to further facilitate pursuit of the various initiatives that the Companies and the State have agreed to undertake in their October 20, 2008 Energy Agreement.

Q. Does the Energy Agreement address accelerated recovery of the Companies' investments?

A. Yes, under the Clean Energy Infrastructure Surcharge ("CEIS") discussion. Per the Energy Agreement, the "CEIS is designed to expedite cost recovery for infrastructure that supports greater use of renewable energy or grid efficiency within the utility systems." It also goes to say "Subject to Commission approval, the CEIS may also be used . . . to accelerate cost recovery."

Q. There is a difference in the accounting treatment (depreciated over Commission approved depreciation rates) and the proposed ratemaking treatment (seven-year straight-line accelerated recovery) for the new AMI meters. Please describe the difference in treatment and how this difference will be accounted for?

A. To clarify, the Companies propose to recover the costs of the new AMI meters over a seven-year period. However, for accounting purposes, the new AMI meters will be depreciated over the Commission approved depreciation rates. The recovery period and depreciation period are separate and distinct. As described in Exhibit 24 of the AMI Application, the difference in the recovery period and depreciation period will result in a situation where the Companies will receive revenues in excess of the costs (depreciation expense) recognized for accounting purposes. Therefore, for accounting and ratemaking purposes, the Companies will record the difference in the REIP or AMI surcharge revenues received, in excess of the current depreciation expenses incurred, as a regulatory liability. The Companies propose to include the regulatory liability balance in their rate bases, as a deduction in the calculation of rate base for ratemaking purposes. As the balance represents ratepayer provided funds, including it as a deduction is proper. Over time, the regulatory liability balance will decrease as the new AMI meters are depreciated. This regulatory liability balance will be zero when the new AMI meters are fully depreciated. Please also see the response to CA-IR-36 for further discussion.

Q. Do the Companies' require any specific approval from the Commission regarding the accounting and ratemaking treatment of the new AMI meters?

A. In order for the Companies to record the difference in AMI surcharge revenues received, in excess of the current depreciation expenses incurred, as a regulatory liability the Companies require Commission approval of the AMI surcharge and of the accounting and proposed ratemaking treatment for the new AMI meters.

EXISTING NON-AMI METERS

Q. What is the Companies' overall position with respect to the accounting and proposed ratemaking treatment for the existing non-AMI meters?

A. The Hawaiian Electric Companies' position is that their investment in the new AMI meters as part of the overall AMI Project is reasonable to meet the objectives of the AMI Project and is in the public interest. As the new AMI meters will be replacing the existing non-AMI meters, the investment made in these existing meters which are installed and in use at customer locations and serving their intended purposes, should be recoverable from ratepayers.

Q. Has the Companies' position with respect to accounting and ratemaking treatment changed from what was presented in the AMI Project Application?

A. No. The Companies' position has not changed.

Q. How do the Companies propose to account for the existing non-AMI meters?

A. The Hawaiian Electric Companies propose to continue depreciating their investment in the existing non-AMI meters over the current Commission approved depreciation rates and to continue to include them as utility assets prior to the meters being replaced. The Companies will retire their existing non-AMI meters as they are replaced by the new AMI meters.

Q. How do the Companies propose to recover their investment in the existing non-AMI meters?

A. For ratemaking purposes and for purposes of calculating the revenue requirements for inclusion in the REIP or AMI surcharge, the Companies propose to accelerate recovery of their investment in the existing non-AMI meters on a straight-line basis beginning with the receipt of the Commission Decision and Order in this docket. The Companies' existing meter investment will be based on the net book value of the existing meters at the receipt of the Commission Decision and Order. The REIP or AMI surcharge would include the net of the revenue requirements of the accelerated recovery of the existing non-AMI meters and the revenue requirements of these meters in base rates, to the extent that the retirement of these meters is not reflected in base rates. Hawaiian Electric proposes recovery over a three-year period beginning upon receipt of the Commission Decision and Order in this docket. MECO and HELCO propose recovery over a period beginning upon receipt of the Commission Decision and Order in this docket and ending when meter installation begins at each of those respective companies. For MECO, meter installation is scheduled to begin in 2014. For HELCO meter installation is scheduled to begin in 2015.

Q. What is the Consumer Advocate's position with respect to the Companies' accounting and proposed ratemaking treatment for the existing non-AMI meters?

A. Similar to the accelerated recovery of the new AMI meters, the Consumer Advocate's witness Mr. Nishina, in CA-T-1, pages 36-37, expressed concerns and recommended that the Commission not approve the accelerated recovery request for the existing non-AMI meters.

Q. What are the Consumer Advocate's concerns?

A. The Consumer Advocate's concerns with respect to existing non-AMI meters are similar to the Consumer Advocate's concerns with respect to the accelerated recovery of the new AMI meters. Ms. Sekimura in HECO T-6 discusses the need for accelerated cost recovery of both the existing non-AMI meters and the new AMI meters.

Q. Why have the Companies proposed to recover their investment in the existing non-AMI meters over an accelerated period?

A. As described in Exhibit 24 of the AMI Project Application, once the existing meters are removed, they will no longer be "used or useful" for utility purposes. Thus, recovery of the investment in these meters should occur within a reasonable time after they are taken out of service. This treatment is consistent with the "stranded" cost recovery concept specified in the Energy Agreement and demonstrates support for the conversion to providing customers expanded alternatives to effectively and efficiently manage their energy use and energy costs. In addition, accelerated recovery over this period will provide improved cash flow and better position the Companies for the AMI meter investment and future investment in advanced AMI-related technologies.

Q. The Companies proposed accelerated recovery will result in different periods of recovery for each of the individual Hawaiian Electric Companies (Hawaiian Electric, MECO and HELCO). Why have the Companies proposed different recovery periods for each company?

A. As described in Exhibit 24 of the AMI Application, the Companies recognize the different recovery periods for each company. Rather than assign three-year recovery periods for all existing non-AMI meters on all islands, MECO and HELCO propose recovery over a longer period which would help smooth out the revenue requirement impact. Assigning a three-year recovery period for MECO and HELCO would possibly result in full recovery of the existing non-AMI meter investment one to two years prior to the installation of the new, advanced solid state meters on these islands. Since installation of the new AMI meters on Maui and Hawaii is scheduled for 2014 and 2015, respectively, there could possibly be a decrease in the revenue requirement impact in the years prior to new meter installation, but after the existing non-AMI meter costs have already been recovered. However, there would be a significant increase when the new meter installation begins on these islands and MECO and HELCO begin recovering these investments. This would create erratic fluctuations in the REIP or AMI surcharge. MECO and HELCO's proposed accelerated recovery period should help smooth out the revenue requirement and lessen the impact to ratepayers.

Q. Why have the Companies proposed to recover the costs of the new AMI meters over a three- to five- year period?

A. As described in response to PUC-IR-9, the Companies evaluated several scenarios with different recovery periods. The impact on the Companies' budget and financing plan, as well as the potential impact on ratepayers, was considered. The recovery periods for each company, as previously described, in conjunction with the seven-year recovery period for the new AMI meters, were found to be the period of time which would provide the Companies a reasonable opportunity to recover their investment in a timely manner, provide cashflow to support the investment in the later years of the project, and also fit the Companies' future financing plans. These recovery periods proposed for each company also helped smooth out the revenue requirement and lessen the impact to ratepayers in any single year (as compared to a shorter recovery period), while at the same time, providing the Companies an opportunity to recover their investment in a more timely manner so as to further facilitate pursuit of the various initiatives that the Companies and the State have agreed to undertake in the Energy Agreement.

Q. The Companies' proposal may result in the investment in the existing non-AMI meters being fully recovered prior to replacement of these meters by the new AMI meters. Please describe why this is reasonable.

A. As described in response to PUC-IR-9, recovery during the proposed periods as described, is reasonable as the existing non-AMI meters are still in service and considered "used or useful" for utility purposes. Prior to being replaced, these meters will still be installed at customer locations, still in use and serving their purposes. The Companies' proposal ensures recovery of and on their investment in these utility assets while they are still in service. In effect, the proposal for recovery over an accelerated period recognizes that these meters will be replaced in the near term and that recovery will be over the meters' approximate remaining useful life. Recovery during this time period provides a more accurate matching of recovery of the investment in the asset with the remaining period of use. It is reasonable and fair to ask ratepayers for recovery of an asset while it is still in use, rather than after or during a period when it has been replaced and is no longer "used and useful".

Q. Similar to the new AMI meters, there is a difference in the accounting treatment (continue depreciation over Commission approved depreciation rates) and the proposed ratemaking treatment (three- to five-year straight-line accelerated recovery) for the existing non-AMI meters. Please describe the difference in treatment and how this difference will be accounted for?

A. To clarify, the Hawaiian Electric Companies propose to recover their investment in the existing non-AMI meters over a three to five year period. However, for accounting purposes the existing non-AMI meters will continue to be depreciated over the Commission approved depreciation rates. The recovery period and depreciation period are separate and distinct. As described in Exhibit 24 of the AMI Application and similar to the treatment of new AMI meters, the difference in the recovery period and depreciation period will result in a situation where the Companies will receive revenues in excess of the costs (depreciation expense) recognized for accounting purposes. Therefore, for accounting and ratemaking purposes, the Companies will record the difference in the REIP or AMI surcharge revenues received, in excess of the current depreciation expenses incurred and in advance of the meters being retired, as a regulatory liability. The Companies propose to include the regulatory liability balance in their rate bases, as a deduction in the calculation of rate base for ratemaking purposes. As the balance represents ratepayer provided funds, including it as a deduction is proper. Over time, the regulatory liability balance will decrease as the existing non-AMI meters are depreciated and replaced. This regulatory liability balance will be zero upon the completion of the meter installation and when all the replaced meters are retired. Please also see the response to CA-IR-36 for further discussion.

Q. Do the Companies require any specific approval from the Commission regarding the accounting and ratemaking treatment of the existing non-AMI meters?

A. In order for the Companies to record the difference in AMI surcharge revenues received, in excess of the current depreciation expenses incurred, as a regulatory liability the Companies' require Commission approval of the AMI surcharge and of the accounting and proposed ratemaking treatment for the existing non-AMI meters.

MDMS SOFTWARE DEVELOPMENT COSTS

Q. What is the Companies' overall position with respect to the accounting and ratemaking treatment for the MDMS software development costs?

A. The Hawaiian Electric Companies' position is that their investment in the MDMS software, as part of the overall AMI Project, is reasonable to meet the objectives of the AMI Project and is in the public interest. The costs of such prudently incurred costs for this project should be recoverable from ratepayers.

Q. Has the Companies' position in this regard changed from what was presented in the AMI Project Application?

A. No. The Companies' position has not changed.

Q. How do the Companies propose to account for the MDMS software development costs?

A. As more fully described in Exhibit 24 of the AMI Project Application, the Companies propose to account for the development of the MDMS software in accordance with Emerging Issues Task Force Bulletin 97-13 ("EITF 97-13"), *Accounting for Costs Incurred in Connection with a Consulting Contract or an Internal Project that Combines Business Process Reengineering and Information Technology Transformation*, and FASB Statement of Position 98-1 ("SOP 98-1"), *Accounting for the Costs of Computer Software Developed or Obtained for Internal Use*, in the same manner as the Commission has approved for other software development projects. Under the Companies' proposal, software development costs incurred during the preliminary stage (i.e., conceptual formation of software alternatives, determination of the existence of needed technology and final selection of alternatives) and post-implementation/operation (i.e., training and application maintenance) of the AMI Project will be expensed as incurred. In the interim, during the application development stage of the AMI Project, the Companies request approval to: 1) defer (i.e., capitalize) certain computer software development costs associated with the MDMS, excluding those costs that should be expensed as incurred such as conversion costs, training, certain overhead costs and EITF 97-13-type costs, if any; 2) accumulate allowance for funds used during construction ("AFUDC") on the deferred costs during the deferral period; 3) amortize the deferred costs over a 12-year period; and 4) include the unamortized costs in rate base.

Q. How do the Companies propose to recover their investment in the MDMS software?

A. If the proposed ratemaking treatment is allowed, the Companies will defer the software development costs (and related AFUDC) of the MDMS and amortize them over a 12-year period. For ratemaking purposes and for purposes of calculating the revenue requirements for inclusion in the AMI surcharge, the Companies propose to defer and amortize the software development costs of the MDMS over a 12-year period and to include the unamortized balance in rate base.

As the MDMS software will be developed and implemented in three separate phases, the Companies propose to amortize the deferred software development costs in each phase separately over a 12-year amortization period. In each phase, as previously described, certain functionalities and features will be designed, coded and installed. The functionalities and features will be installed and ready for use at three different times (at the end of each phase). Therefore, the Companies propose to track and defer the costs incurred in each phase separately and to begin amortization in the month after the functionalities installed in that particular phase are deemed operational and ready for their intended use. The costs deferred specific to each individual phase will be amortized over 12 years.

Q. Do the Companies require any specific approval from the Commission regarding the accounting and proposed ratemaking treatment of the MDMS software development costs?

A. In Decision and Order No. 18365, filed February 8, 2001 in Docket No. 99-0207 (HELCO's 2000 test year rate case), the Commission ruled that its pre-approval is required before any computer software development project costs can be deferred and amortized for ratemaking purposes. Therefore, in order for the Companies to defer the MDMS software development costs (and related AFUDC) and amortize them over a 12-year period, the Commission needs to approve the requested treatment.

Q. What would happen if the Companies' accounting and proposed ratemaking treatment were not adopted by the Commission?

A. The Companies would have to record the software development costs as expenses when incurred.

Q. What is the Consumer Advocate's position with respect to the Companies' accounting and proposed ratemaking treatment for its MDMS software development costs?

A. The Consumer Advocate's witness, Mr. Nishina, in CA-T-1, pages 37-38, expressed some concerns with the proposed deferral of the software development costs. Mr. Nishina acknowledges that the 12-year amortization period is consistent with past proceedings on software development projects approved by the Commission. However, he questions whether a longer recovery period is more appropriate with the expectation that the Companies should not replace the system within 12 years.

Q. Please describe why a 12-year amortization period is reasonable?

A. As described in the response to PUC-IR-10, under the accounting guidance of SOP 98-1, the amortization period for software development costs should be the expected useful life of the developed software. While the expected useful life of the MDMS software has not yet been determined (as the MDMS software has not yet been selected), it is anticipated that the expected useful life may actually be less than 12 years due to the rapid pace of technological change. Therefore, a 12-year amortization period may in actuality be longer than the expected useful life of the system. In addition, the 12-year amortization period is consistent with the approved amortization periods of the Companies' other deferred software development projects including the Customer Information System ("CIS"),[1] Outage Management System ("OMS")[2] and Human Resource Management System ("HRMS")[3] projects.

Q. The Consumer Advocate indicated that the Commission should make clear certain items regarding the accounting for the MDMS costs, similar to other systems development projects. What is Hawaiian Electric's position?

A. The Consumer Advocate has indicated that all process re-engineering costs should be properly identified and expensed. Hawaiian Electric agrees that costs related to

---

[1] See Decision and Order No. 21798, Docket No. 04-0268, issued May 3, 2005.
[2] See Decision and Order No. 21899, Docket No. 04-0131, issued June 30, 2005.
[3] See Decision and Order No. 23413, Docket No. 2006-003, issued May 3, 2007.

process re-engineering will be expensed, consistent with EITF 97-13 as the company has done for other software development projects (i.e., the CIS, OMS, and HRMS projects). The Consumer Advocate has also requested that the Companies maintain the appropriate documentation to support the classification of actual costs. The Companies will maintain the appropriate documentation to support the classification of the actual costs between capital, deferred and expense. Finally the Consumer Advocate recommended that capitalized costs not include general and administrative costs and overheads as stated in SOP 98-1. The Companies agree that it will follow SOP 98-1 in reflecting the costs that could be deferred.

AMI NETWORK LEASE EXPENSE

Q. How do the Companies propose to account for the agreement with Sensus?

A. As discussed in Exhibit 24 of the AMI Application, HECO has determined that the agreement contains a lease, and that the lease is an operating lease. However, based on Statement of Financial Accounting Standards No 13, the lease payments over the fixed term of the lease must be recorded on a straight-line basis over the fixed term of the lease, even if the payments are not made on a straight-line basis.

Q. What is the Companies' proposal regarding the ratemaking treatment of the lease?

A. As discussed in Exhibit 24 of the AMI Application, the Companies propose that the ratemaking be based on the lease payments as they are paid over the term of the lease. The Companies request that the Commission indicate that the recovery will be based on the lease payments over the term of the lease. With such approval, the Company will be able to record a regulatory asset/regulatory liability for the difference between the straight-line expense required under generally accepted accounting principles ("GAAP") and the lease payments under the agreement. In the early years of the 15-year lease term, the regulatory asset balance will grow as the straight-line lease expenses will be in excess of the actual lease payments made. As the lease agreement progresses through the 15-year term, the actual lease payments made will be higher than the straight-line lease expenses. This difference will reduce the regulatory asset balance until eventually the regulatory asset balance will be zero at the end of the fixed lease term. This treatment will allow for a matching of the revenues received and the book recognition of the lease expense, resulting in no earnings impact. This regulatory asset would not be included in rate base as it does not represent investor provided funds.

Q. Did the Consumer Advocate have concerns about this method?

A. It is not quite clear, since the Consumer Advocate's witness Mr. Nishina in CA-T-1, pages 38-39 indicates the Companies' proposal to recover the lease expense on a straight-line basis for ratemaking purposes seems reasonable. The Consumer Advocate further indicated that it should be clarified that if the Companies are allowed to recover a certain level of costs early such that there is a difference between book and regulatory treatment, it may be necessary to reflect the difference in rate base as an offset. As stated above, the Companies' proposal is for ratemaking to be based on the lease payments over the entire term of the lease. However, if the Consumer Advocate and the Commission prefer that the recovery of the lease expenses be on a straight-line basis consistent with GAAP, the Company would be agreeable, and would reflect the difference between the actual expense and the payments under the lease agreement in rate base.

COST RECOVERY

Q. Please describe the Companies' proposal to recover the net incremental costs of the AMI Project.

A. The Companies propose to recover the net incremental AMI Project revenue requirement through an adjustment clause that better matches cost recovery with cost incurrence. In particular, the Companies propose that the adjustment clause be implemented by means of the proposed REIP Surcharge or in the alternative, through an AMI surcharge. The Companies propose recovery on a prospective basis, subject to reconciliation.

Q. *Please describe what is meant by the net incremental costs of the AMI Project?*

A. The net incremental costs refer to the incremental costs of the AMI Project less the incremental quantifiable benefits created by the project. Thus, the Companies are not proposing to collect all of the AMI Project's cost through a surcharge. The Companies only propose to flow the project's net incremental revenue requirement through the surcharge to the extent that the net incremental revenue requirements are not captured in base rates or any other surcharge mechanism. Accordingly, the AMI Project costs recovered through the surcharge will be net of the incremental quantifiable benefits created by the AMI Project which are not captured in base rates or any other surcharge mechanism.

Q. Will the Companies include all reasonably identifiable and quantifiable benefits in determining the net incremental cost subject to recovery under the REIP or AMI surcharge?

A. Yes. The Companies will include all reasonably identifiable and quantifiable benefits arising as a result of the AMI Project in determining the net incremental cost to be recovered through the REIP or AMI surcharge. To the extent that these benefits are not captured in base rates or in any other surcharge mechanism they will be net against the incremental costs of the AMI Project. The quantifiable benefits will be tracked and accounted for as described in the Companies' response to CA-IR-36. Also, the Companies are developing general accounting guidelines which will allow consistent and accurate accounting for the incremental costs and quantifiable benefits of the AMI Project. Preliminary accounting guidelines have been developed (subject to change based on additional analyses, discussions, guidance, proceeding progress and/or receipt of Commission decision and order in this proceeding) and were included as Attachment 1 in the response to CA-IR-36. Further discussion of the incremental costs and benefits of the AMI Project is presented by Mr. Andy Hignite in HECO-T-3.

SUMMARY

Q. Please summarize your testimony.

A. The Companies' accounting treatment for the new AMI meters mirrors the accounting for other capital projects constructed in the normal course of business. The Companies request the Commission to explicitly approve the Companies' proposed ratemaking treatment for the new AMI meters to recover the capital costs over a seven-year period on a straight-line basis. The proposed ratemaking treatment will provide the Companies an opportunity to recover their investment in a timelier manner. It will also provide for improved cash flow and better position the Companies for future investment in advanced AMI-related technologies while also facilitating the pursuit of the various initiatives that the Companies and the State have agreed to undertake in the Energy Agreement.

The Companies' accounting treatment for the existing non-AMI meters mirrors the accounting currently in place for those meters. The Companies request the Commission to explicitly approve the Companies' proposed ratemaking treatment for the existing non-AMI meters to recover the remaining net book value of those meters on a straight-line basis over the periods described previously in this testimony. The proposed ratemaking treatment will allow the Companies to recover their investment in these existing non-AMI meters while they are in service and within a reasonable time after they are replaced and taken out of service.

The Companies' accounting and proposed ratemaking treatment for the MDMS software development costs mirrors the accounting and ratemaking treatment for other software development projects. The proposed accounting and ratemaking treatment is reasonable and consistent with prior Commission decisions. The Companies request the Commission to explicitly approve the proposed accounting and ratemaking treatment for the MDMS software development costs. Commission approval will allow the Companies' to defer the software development costs and accrue AFUDC during the deferral period. Commission approval will also allow the Companies' to amortize the deferred costs over a 12-year period and to include the unamortized balance of deferred costs (including AFUDC) in rate base.

The Companies propose that the ratemaking treatment for the AMI Network lease expense be based on the lease payments over the entire term of the lease.

Q. Does this conclude your testimony?

A. Yes, it does.

HAWAIIAN ELECTRIC COMPANY, INC.

PATSY H. NANBU

EDUCATIONAL BACKGROUND AND EXPERIENCE

BUSINESS ADDRESS:	Hawaiian Electric Company, Inc. 900 Richards Street Honolulu, HI 96813
POSITION:	Controller, Hawaiian Electric Company, Inc.
PREVIOUS POSTIONS:	Director, Regulatory Affairs Director, Internal Audit Senior Regulatory Analyst Budget Administrator Budget Analyst
YEARS OF SERVICE:	23 years
EDUCATION:	Bachelor of Business Administration in Accounting with Distinction, University of Hawaii, 1981 Master of Accountancy, University of Hawaii, 1983
PROFESSIONAL REGISTRATION:	Certified Public Accountant (not in public practice) State of Hawaii, 1984
OTHER EXPERIENCE:	Senior Auditor, Arthur Young & Company
TESTIMONY:	Docket No. 2008-0083 – HECO 2009 TestYear Rate Case Administrative & General Expense; Standard Labor Rates, Information Technology Services, Accounting for Computer Software Development Costs; Abandoned Capital Project Costs, Unamortized Gain on Sale of Land; Iolani Court Plaza Lease Premium; Accounting for Reverse Osmosis Water Pipeline Costs; Accounting for Pensions and Postretirement Benefits Other than Pensions; General Accounting Department Staffing

TESTIMONY: (continued)	Docket No. 2006-0386 – HECO 2007 Test Year Rate Case Administrative &General Expense; Budgeting Process; Accounting for Computer Software Development Costs; Abandoned Capital Project Costs; Unamortized Gain on Sale of Land; Iolani Court Plaza Lease Premium; Accounting for Pensions and Postretirement Benefits Other than Pensions; General Accounting Department Staffing
	Docket No. 05-0315 – HELCO 2006 Test Year Rate Case – Accounting Policy – Allowance for Funds Used During Construction
	Docket No. 05-0145 – Campbell Industrial Park Generation Station Project Community Benefits Package - Accounting and Ratemaking Treatment for Reverse Osmosis Water Pipeline Project and Environmental Monitoring Programs

HECO T-6
DOCKET NO. 2008-0303

TESTIMONY OF
TAYNE S.Y. SEKIMURA

SENIOR VICE PRESIDENT
FINANCE AND ADMINISTRATION
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Need for Accelerated Cost Recovery

INTRODUCTION

Q. Please state your name and business address.

A. My name is Tayne S.Y. Sekimura and my business address is 900 Richards Street, Honolulu, Hawaii.

Q. What is your present position?

A. I am the Senior Vice President, Finance and Administration for Hawaiian Electric Company, Inc. ("Hawaiian Electric"). My educational background and experience are listed in HECO-600.

Q. What will your testimony address?

A. My testimony will address the need for the accelerated cost recovery of the investment in the new AMI meters and existing non-AMI meters as presented in the Advanced Metering Infrastructure ("AMI") Project Application proposed by Hawaiian Electric, Hawaii Electric Light Company, Inc. ("HELCO") and Maui Electric Company, Limited ("MECO") (collectively, the "Hawaiian Electric Companies" or "Companies"). I will also address the Consumer Advocate's concerns and recommendation that the Commission not approve the accelerated cost recovery. Specifically, I will address the Consumer Advocate's concern that the Hawaiian Electric Companies has not received information from the credit rating agencies supporting the assertion that the Companies' credit rating will be negatively impacted without approval of the proposed accelerated recovery.

NEED FOR ACCELERATED COST RECOVERY

Q. What is the Companies' position with respect to the proposed accelerated cost recovery of its investment in the new AMI meters and the existing non-AMI meters?

A. The Companies' position with respect to the proposed accelerated cost recovery of the new AMI meters and existing non-AMI meters is that it will provide improved cash flow, better position the Companies for the AMI meter investment and better position the Companies for future investment in advanced AMI-related technologies. An accelerated cost recovery mechanism would enable the Companies to begin recovering their investment much more quickly than waiting for recovery under a traditional rate case proceeding mechanism. Further, an accelerated cost recovery period could reduce investors' perception of risk by limiting the uncertainty in the recovery of the Companies' investment. In turn, this may help maintain the Companies' current cost of capital and mitigate a potential degradation in credit quality.

Q. Have other jurisdictions addressed the need for accelerated cost recovery?

A. Yes. As noted in the Companies' responses to PUC-IRs 8 and 9, other commissions such as the Federal Energy Regulatory Commission and the Public Utility Commission of the State of Oregon have recognized the use of accelerated depreciation as a means for the recovery of electric system infrastructure.

Q. Has the Companies' position with respect to the need for accelerated cost recovery changed from what was presented in the AMI Project Application?

A. No. The Companies' position has not changed.

Q. What is the Consumer Advocate's position with respect to the Companies' accounting and proposed ratemaking treatment for the new AMI meters and existing non-AMI meters, particularly the need for accelerated cost recovery?

A. The Consumer Advocate's witness Mr. Nishina, in CA-T-1, page 36-37, expressed concern with the accelerated recovery of the Companies' investment in the new AMI meters and existing non-AMI meters. Mr. Nishina recommended that the Commission not approve the accelerated recovery request for both the new AMI meters and existing non-AMI meters.

Q. What are the Consumer Advocate's concerns?

A. The Consumer Advocate has expressed concerns that: 1) it has not received information from the credit rating agencies supporting the Hawaiian Electric Companies' assertion that the Companies' credit rating will be negatively impacted without approval of the accelerated recovery; 2) the requested accelerated recovery is not entirely consistent with the Energy Agreement; and 3) there is a difference in the seven-year accelerated recovery period and the longer book depreciation period. I will address the Consumer Advocate's first concern below. Ms. Patsy Nanbu will address the remaining concerns in HECO-T-5.

Q. Have the Companies received any direct communications from rating agencies specifying that the Companies' credit rating will be adversely impacted without approval of the requested accelerated recovery?

A. No, the Companies have not received direct communications from ratings agencies or other sources. However, as presented in the Companies' response to CA-IR-26, part c, Standard & Poor's ("S&P") view[1] is that regulatory support for mechanisms which provide for timely cost recovery and help address the issue of regulatory lag are supportive of utility creditworthiness. In addition, S&P does address the importance of limiting uncertainty in the recovery of utility investments. An REIP or AMI surcharge with an accelerated cost recovery mechanism would enable the Hawaiian Electric Companies to begin recovering their investment much more quickly than waiting for recovery in a rate case

---

[1] Standard & Poor's, "Key Credit Factors: Business And Financial Risks In The Investor-Owned Utilities Industry", November 26, 2008 (See HECO-601) and Standard & Poor's, RatingsDirect, "Recovery Mechanisms Help Smooth Electric Utility Cash Flow and Support Ratings", March 9, 2009 (See HECO-602)

proceeding, with a longer recovery period. This accelerated recovery mechanism would serve to mitigate the risks and limit the uncertainty in the timeliness of recovery of the Companies' investment, as well as allow for improved cash flow. S&P cited these factors which may help mitigate a potential degradation in credit quality.

SUMMARY

Q. Please summarize your testimony.

A. The Companies' proposed accelerated recovery of its investment in the new AMI meters and existing non-AMI meters will provide for improved cash flow and better position the Companies for the new AMI meter investment, as well as for future investment in advanced AMI-related technologies. Further, an accelerated cost recovery period could reduce investors' perception of risk by limiting the uncertainty in the recovery of the Companies' investment. In turn, this may help maintain the Companies' current cost of capital and mitigate a potential degradation in credit quality.

Q. Does this conclude your testimony?

A. Yes, it does.

HAWAIIAN ELECTRIC COMPANY, INC.

TAYNE S. Y. SEKIMURA

EDUCATIONAL BACKGROUND AND EXPERIENCE

Present employer:	Hawaiian Electric Company, Inc. 900 Richards Street Honolulu, HI 96813
Current position:	Senior Vice President, Finance & Administration
Previous positions:	Financial Vice President Director, Corporate and Property Accounting Director, Internal Audit Capital Budgets Administrator
Years of service:	18 years
Other experience:	Audit Manager, KPMG Assistant Controller, Long Distance/USA
Certification:	Certified Public Accountant (not in public practice) State of Hawaii
Education:	University of Hawaii at Manoa Bachelor of Business Administration in Accounting
Testimonies:	Hawaiian Electric Company, Inc. Docket No. 2008-0083 – Rate of Return on Rate Base Maui Electric Company, Ltd. Docket No. 2006-0387 – Cost of Capital Hawaiian Electric Company, Inc. Docket No. 2006-0386 – Cost of Capital Hawaii Electric Light Company, Inc. Docket No. 05-0315 – Cost of Capital

Testimonies: *(continued)*	Hawaiian Electric Company, Inc. *Docket No. 04-0113 – Depreciation Expense and Accumulated* Depreciation; Total Average Number of Employees; King Street Office Building Lease; Prepaid Pension Asset; Gains on Sale of Land and Iolani Court Plaza Lease Premium; Accounting for Computer Software Development Costs; Abandoned Capital Project Costs; Maintaining Financial Integrity; and Cost of Capital
	Maui Electric Company, Ltd. Docket No. 94-0345 – Rate Base
	Hawaii Electric Light Company, Inc. Docket No. 94-0140 – Rate Base

STANDARD & POOR'S

My Credit Profile
Hawaiian Electric Industries Inc., HI - 'BBB/Stable/A-2'

Table of Contents

Key Credit Factors: Business And Financial Risks In The Investor-Owned Utilities Industry

Publication date: 26-Nov-2008

Primary Credit Analyst: Todd A Shipman, CFA, New York (1) 212-438-7676; todd_shipman@standardandpoors.com

Standard & Poor's Ratings Services' analytic framework for companies in all sectors, including investor-owned utilities, is divided into two major segments: The first part is the fundamental business risk analysis. This step forms the basis and provides the industry and business contexts for the second segment of the analysis, an in-depth financial risk analysis of the company.

An integrated utility is often a part of a larger holding company structure that also owns other businesses, including unregulated power generation. This fact does not alter how we analyze the regulated utility, but it may affect the ultimate rating outcome because of any higher risk credit drag that the unregulated activities may have on the utility. Such considerations include the freedom and practice of management with respect to shifting cash resources among subsidiaries and the presence of ring-fencing mechanisms that may protect the utility.

Relationship Between Business And Financial Risks

Prior to discussing the specific risk factors we analyze within our framework, it is important to understand how we view the relationship between business and financial risks. Table 1 displays this relationship and its implications for a company's rating.

Table 1 | Download Chart Data

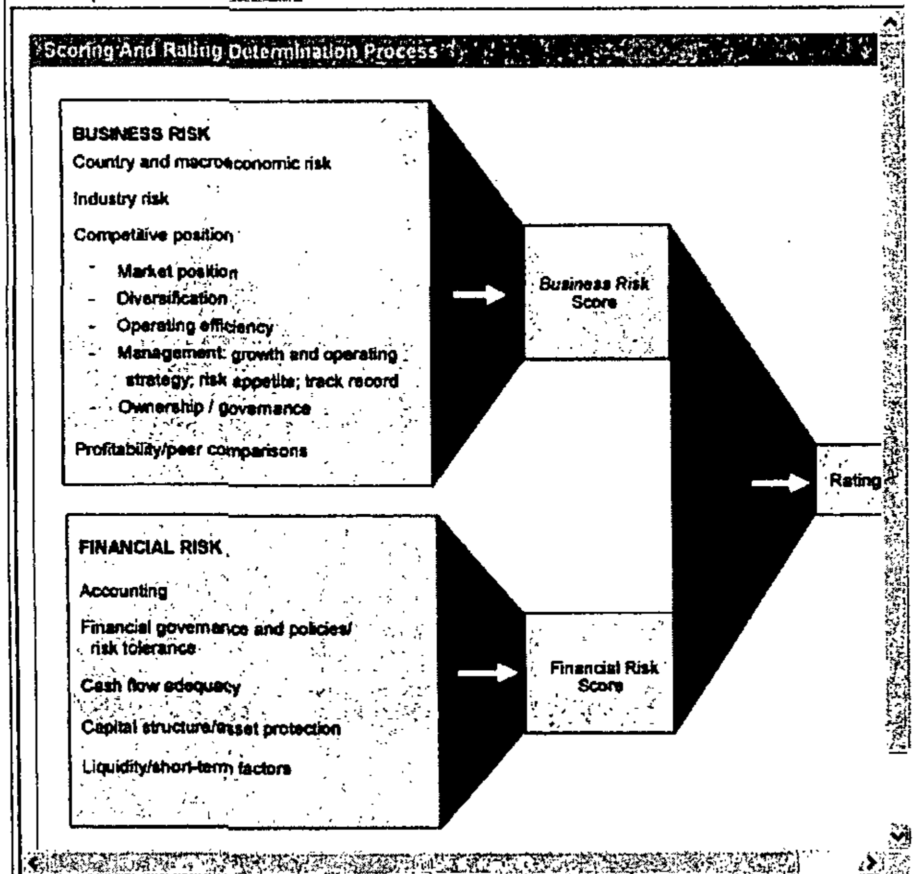
Business And Financial Risk Profile Matrix

Business Risk Profile		Financial Risk Profile: [illegible]	[illegible]	[illegible]	[illegible]	[illegible]
		(AAA/AA)	(A)	(BBB)	(BB)	(B)
[illegible]	(AAA/AA)	AAA	AA	A	BBB	BB
[illegible]	(A)	AA	A	A-	BBB-	BB-
[illegible]	(BBB)	A	BBB+	BBB	BB+	B+
[illegible]	(BB)	BBB	BBB-	BB+	BB-	B
[illegible]	(B)	BB	B+	B+	B	B-

These rating outcomes are shown for guidance purposes only. Other qualitative and quantitative rating factors may override these measures.

Chart 1 summarizes the ratings process.

Chart 1 | Download Chart Data



Part 1--Business Risk Analysis

Business risk is analyzed in four categories: country risk, industry risk, competitive position, and profitability. We determine a score for the overall business risk based on the scale shown in table 2.

Table 2 | Download Table

Business Risk Measures

Description	Rating equivalent
Excellent	AAA/AA
Strong	A
Satisfactory	BBB
Weak	BB
Vulnerable	B/CCC

Analysis of business risk factors is supported by factual data, including statistics, but ultimately involves a fair amount of subjective judgment. Understanding business risk provides a context in which to judge financial risk, which covers analysis of cash flow generation, capitalization, and liquidity. In all cases, the analysis uses historical experience to make estimates of future performance and risk.

In the U.S., regulated utilities and holding companies that are utility-focused virtually always fall in the upper range (Excellent or Strong) of business risk profiles. The defining characteristics of most utilities--a legally defined service territory generally free of significant competition, the provision of an essential or near-essential service, and the presence of regulators that have an abiding interest in supporting a healthy utility financial profile--underpin the business risk profiles of the electric, gas, and water utilities.

1. Country risk and macroeconomic factors (economic, political, and social environments)

Country risk plays a critical role in determining all ratings on companies in a given national domicile. Sovereign-related stress can have an overwhelming effect on company creditworthiness, both directly and indirectly.

Sovereign credit ratings suggest the general risk local entities face, but the ratings may not fully capture the risk applicable to the private sector. As a result, when rating a corporation, we look beyond the sovereign rating to evaluate the specific economic or country risks that may affect the entity's creditworthiness. Such risks pertain to the effect of government policies and other country risk factors on the obligor's business and financial environments, and an entity's ability to insulate itself from these risks.

2. Industry business and credit risk characteristics

In establishing a view of the degree of credit risk in a given industry for rating purposes, it is useful to consider how its risk profile compares to that of other industries. Although the industry risk characteristic categories are broadly similar across industries, the effect of these factors on credit risk can vary markedly among industries. Chart 2 illustrates how the effects of these credit-risk factors vary among some major industries. The key industry factors are scored as follows: High risk (H), medium/high risk (M/H), medium risk (M), low/medium risk (L/M), and low risk (L).

Chart 2 | Download Chart Data

Key Industry Characteristics And Drivers Of Credit Risk

	Utilities regulated	Competitive power	Oil & gas downstream	Autos	Airlines
Industry dynamics and competitive environment					
Industry cyclicality	M	H	H	H	H
Ease of entry	L	M/H	H	M/H	M/H
Product cycle/obsolescence	L	L	L	H	L
Level of product quality	L	L	M	H	M
Disintermediation/substitution	L	L	L	L/M	L
Competition/commoditization	L/M	H	M	H	H
Pricing inflexibility	M	H	M	H	H
Business model stability	M	M/H	L	L/M	M
Demographic trends	L	L	M	H	L
Growth and profitability					
Growth outlook	L	M	L	M/H	L/M
Profit margin pressure/outlook	M	M/H	M	M/H	H
Earnings volatility	M	M/H	H	H	H
Operating considerations and costs					
Technological risk/change	L	L	L/M	L/M	L/M
Cost efficiency/pressures	M	H	M	H	H
Operating leverage	M/H	H	H	H	H
R&D costs	L	L	L	H	L
Energy cost sensitivity	H	H	H	H	H
Raw material cost sensitivity	H	H	H	H	L
Labor costs	M	M	M	H	H
Labor inflexibility/unrest	L	L	M	H	H
Pension costs/contingents	M	L	L/M	H	M/H
Environmental impact/costs	H	L	H	H	M/H
Marketing costs	L	L	M	H	L/M
Customer concentration	L	M	L	L	L
Supplier concentration	H	H	H	M	M
Risk management	M	H	M	M	M
Asset/plant quality and upkeep	M	H	H	M	M/H
Event risk sensitivity	M/H	H	H	M/H	H
Financial market volatility/sensitivity	M	M/H	L	M	M
Fashion/fad/taste sensitivity	L	L	L	H	L/M
Capital and financing characteristics					
Capital intensity	H	H	H	H	H
Borrowing requirement	H	H	L/M	H	H
Interest rate sensitivity	L/M	L/M	L/M	H	L/M
Government, regulatory, and legal environments					
Regulation/deregulation	H	H	M	M/H	H
Government macroeconomic and social policies	H	H	H	H	M/H
Litigiousness/legal risk	L	H	M	M	M

Industry strengths:

- Material barriers to entry because of government-granted franchises, despite deregulatory trends;
- Strategically important to national and regional economies; key pillar of the consumer and commercial economy;
- Improving management focus industry-wide on operating efficiency in recent years; and
- Cross-border growth opportunities in Europe and industrializing emerging markets.

Industry challenges/risks:

- Maturity, with a weak growth outlook in developed countries;
- Highly politicized and burdensome regulatory (i.e., rate setting and investment recovery) process; and
- Risks of "legacy cost drag" as wholesale and retail markets move toward greater deregulation.

Major global risk issues facing the utilities industry:

- Increased volatility in the regulatory environment and competitive landscape leading to greater uncertainty regarding adequacy of pricing and return on capital;
- Longer-term impact of, and ability to absorb, significant secular upturn in fuel costs, which is the industry's major operating expense;
- Ability to recover massive investment costs that will likely be necessary to replace aging industry infrastructure in a harsher cost and regulatory environment; and
- The debate over global warming will continue far beyond 2008. What the ultimate outcome will be is unclear, but growing legislation addressing carbon emissions and other greenhouse gases is probable in the near future. Utilities' ability to recover environmentally mandated costs in authorized rates and consumers' willingness to pay them could impact the industry's future credit strength.

Industry business model and risk profile in transition

Regulated utilities are in many developed countries transitioning away from quasi-monopolies toward more open competitive environments.

The level of business and credit risk associated with the investor-owned regulated utilities has historically proven in most countries to be lower (risk) than for many other industries. This has been because of the existence of government policy and related regulation that created significant barriers to entry limiting competition, and regulatory rate setting designed to provide an opportunity to achieve a specific level of profitability. The credit quality of most vertically integrated utilities in developed countries has historically been, and remains, solidly investment grade. This, to reiterate, is primarily a function of the existence of protective regulation.

The risks of, and rationale for, deregulation

The traditional protected and privileged utilities industry business model with its marked monopolistic characteristics is in many countries undergoing transition to a more competitive and open framework. This transition process, known as deregulation or liberalization, is weakening the business and credit risk profile of the industry. While the impact of these changes may prove positive in the longer term for more efficient industry players, it is important to bear in mind that economic history is littered with the vestiges of industries and enterprises that once flourished under the protection of government-created barriers and other protections. The shift is being driven by introduction in many countries of policies to encourage the entrance of new competitors and to reduce the traditional regulatory protections and privileges enjoyed by incumbents. Historically, the regulated investor-owned utilities were usually granted exclusive franchises. Because of the significant risks associated with the capital-intense nature of the utility investment, including massive sunk/fixed costs and long-term break-even horizons, governments in many countries created legal and regulatory frameworks that granted exclusivity to one operator in a given geographic area. To offset the monopolistic pricing power this exclusivity created, a system of heavy regulation was typically developed, which included the setting of pricing. The model often set pricing on a "cost-plus-basis", i.e., the margin over cost allowing for a perceived fair return to shareholders of investor-owned utilities. One major weakness of this system is that it created little incentive for utilities to efficiently manage costs. In recent years as many governments have adopted more liberal open market economic philosophies and related policies focused on the creation of greater competition—in an effort to foster improved economic growth and pricing efficiency throughout the economy—the traditional utility models in many countries have come under increasing political scrutiny and pressure.

A major public policy and political risk, as well as a credit risk, associated with deregulation of protected industries, is that existing incumbents often experience significant challenges in readjusting their management strategies, cultures, and expense basis to be able to compete effectively in the new environment.

The turmoil and bankruptcies in the U.S. in the nonregulated power marketing and trading arena between 2000 and 2002 arose subsequent to a major government initiative to deregulate the wholesale market. These failures, as well as other high-profile problems arising from deregulation elsewhere in the world, have given governments pause as to the desirability of a headlong rush into deregulation. In the U.S., for example, there is currently little impetus to carry deregulation any further.

Regulation and deregulation in the U.S.

While considerable attention has been focused on companies in states that deregulated in the late 1990s and the early part of this decade, and the related consequences of disaggregation and nonregulated generation, 27 states (plus four that formally reversed, suspended, or delayed restructuring) have retained the traditional regulated model. For utilities operating in those states, the quality of regulation and management loom considerably larger than markets, operations, and competitiveness in shaping overall financial performance. Policies and practices among state and federal regulatory bodies will be key credit determinants. Likewise, the quality of management, defined by its posture towards creditworthiness, strategic decisions, execution and consistency, and its ability to sustain a good working relationship with regulators, will be key. Importantly, however, it is virtually impossible to completely segregate each of these characteristics from the others; to some extent they are all interrelated.

Fragmentation of original model emerges in the U.S.

- Traditional regulated, vertically integrated utilities (generation, transmission, and distribution);
- Transmission and distribution;
- Diversified;
- Transmission; and
- Merchant generation.

We view a company that owns regulated generation, transmission, and distribution operations as positioned between companies with relatively low-risk transmission and distribution operations and companies with higher-risk diversified activities on the business profile spectrum. What typically distinguishes one vertically integrated utility's business profile score from another is the quality of regulation and management, which are the two leading drivers of credit quality.

Deregulation in the U.S. creates a new volatile industry subsector

The birth of large-scale, nonregulated power generators created the opportunity--and the need--for companies to market and broker power. Power marketers, independent power producers, and unregulated subsidiaries of utility companies offer power-supply alternatives to other utilities in the wholesale market as well as to large industrial customers. Power marketing operations have been formed by energy companies (many with experience in marketing natural gas), utility subsidiaries, and independents. As with the gas industry, electric power marketers expected to develop an efficient market by straddling the gulf between electricity generators and their customers, who have become "free agents" in the newly competitive environment.

Deregulation creates tiering of industry, business and credit risk profiles in Europe

The regional differences in market liberalization across Western Europe result in material variations in industry and business risk profiles for the utilities industry at the national level. The U.K. and Nordic markets, in particular, are substantially deregulated and open, and consequently present higher risks than other markets that are less open, including France and the Iberian market. Ratings therefore generally are lower in these more deregulated markets. The less-liberalized markets may face more regulatory risk going forward, particularly if efforts by the EU to advance the internal market by increasing the extent of market liberalization across the EU continue.

Legal action against companies that infringe on competition laws should be expected--particularly against those that move to prevent new entry and limit customer choice (for example, through the tying of markets and capacity hoarding) or collude with other incumbents to do so. The European Commission (EC) can fine companies that have violated antitrust laws up to 10% of their global annual turnover and, under certain conditions, impose structural remedies. Particular emphasis would be placed on increasing the effective unbundling of network and supply activities and on diminishing market concentration and barriers to entry.

The EC has publicly stated is intention to pursue, as a priority, abuses of the dominant position of vertically integrated companies (called vertical foreclosure). Behavioral remedies, such as energy release programs, are expected to be imposed by the EC for which such abuses, or collusion, are proved. The commission could also enforce structural measures when behavioral remedies are deemed insufficient.

3. Company competitive position and keys to competitive success

In analyzing a company's competitive position, we consider the following:

- Regulation;
- Markets;
- Diversification;
- Operations;
- Management, including growth strategy;
- Governance; and
- Profitability.

We are most concerned about how these elements contribute individually and in aggregate to the predictability and sustainability of financial performance, particularly cash flow generation relative to fixed obligations.

Regulation. Critical success factors include:

- Consistency and predictability of decisions;
- Support for recovery of fuel and investment costs;
- History of timely and consistent rate treatment, permitting satisfactory profit margins and timely return on investment; and
- Support for a reasonable cash return on investment.

Regulation is the most critical aspect that underlies regulated integrated utilities' creditworthiness. Regulatory decisions can profoundly affect financial performance. Our assessment of the regulatory environments in which a utility operates is guided by certain principles, most prominently consistency and predictability, as well as efficiency and timeliness. For a regulatory process to be considered supportive of credit quality, it must limit uncertainty in the recovery of a utility's investment. They must also eliminate, or at least greatly reduce, the issue of rate-case lag, especially when a utility engages in a sizable capital expenditure program.

Our evaluation encompasses the administrative, judicial, and legislative processes involved in state and national government regulation, and includes the political environment in which commissions render decisions. Regulation is assessed in terms of its ability to satisfy the particular needs of individual utilities. Rate-setting actions are reviewed case by case with regard to the potential effect on credit quality.

Evaluation of regulation focuses on the ability of regulation to provide utilities with the opportunity to generate cash flow and earnings quality and stability adequate to:

- Meet investment needs;
- Service debt and maintain a satisfactory rating profile; and
- Generate a competitive rate of return to investors.

To achieve this, regulation must allow for:

- Timely recognition of volatile cost components such as fuel and satisfactory returns on invested capital and equity;
- Ability to enter into long-term arrangements at negotiated rates without having to seek regulatory approval for each contract; and
- Ability to recover costs in new investment over a reasonable time frame.

Because the bulk of a utility's operating expenses relate to fuel and purchased power, of primary importance to rating stability is the level of support that state regulators provide to utilities for fuel cost recovery, particularly as gas and coal costs have risen. Utilities that are operating under rate moratoriums, or without access to fuel and purchased-power adjustment clauses, or face significant regulatory lag, also are subject to reduced operating margins, increased cash flow volatility, and greater demand for working capital. Companies that are granted fuel true-ups may be required to spread recovery over many years to ease the pain for the consumer. In addition to fuel cost recovery filings, regulators will have to address significant rate increase requests related to new generating capacity additions, environmental modifications, and reliability upgrades. Current cash recovery and/or return by means of construction work in progress support what would otherwise sometimes be a significant cash flow drain and reduces the utility's need to issue debt during construction.

Markets/market position. Critical success factors include:

- A healthy and growing economy;
- Growth in population and residential and commercial customer base;
- An attractive business environment;
- An above-average residential base; and
- Limited bypass risk.

The importance of diversification and size. Critical success factors include:

- Regional and cross-border market diversification (mitigates economic, demographic, and political risk concentration);
- Industrial customer diversification;
- Fuel supplier diversification;
- Retail, compared with wholesale;
- Regulatory regime diversification; and
- Generating facility diversification.

Operations (operating strategy, capability, and performance efficiency). Critical success factors include:

- Low cost structure;
- Well-maintained assets;
- Solid plant performance;
- Adequate generating reserves, and compliance with environmental standards; and
- Limited environmental exposures.

Management evaluation. Utilities are complex specialized businesses requiring experienced and successful management teams to have a strong mix of the aforementioned disciplines. Critical elements of management success include:

- Commitment to credit quality;
- Operating efficiency and cost control;
- Maintaining a competitive asset base, i.e., power plant construction project management, and plant upkeep and renovation;
- Regulatory track record, process, and relationship management;
- M&A experience in successfully identifying, executing, and integrating acquisitions;
- Credibility and strong corporate governance;
- Conservative financial policies, especially regarding non-regulated activities; and
- Ability and track record in repositioning and transforming business to not just survive, but prosper in a more open market environment.

Management is assessed for its ability to run and expand the business efficiently, while mitigating inherent business and financial risks. The evaluation also focuses on the credibility of management's strategy and projections, its operating and financial track record, and its appetite for assuming business and financial risk.

The management assessment is based on tenure, turnover, industry experience, financial track record, *corporate governance, a grasp of industry issues, and knowledge of regulation, the impact of* deregulation, of customers, and their needs. Management's ability and willingness to develop workable strategies to address system needs, and to execute reasonable and effective long-term plans are assessed. Management quality is also indicated by thoughtful balancing of multiple priorities; a record of credibility; and effective communication with the public, regulatory bodies, and the financial community.

We also focus on management's ability to achieve cost-effective operations and commitment to maintaining credit quality. This can be assessed by evaluating accounting and financial practices, capitalization and common dividend objectives, and the company's philosophy regarding growth and risk-taking.

4. Profitability/peer comparison

Regulated. Traditionally, the lower levels of risk in utilities because of the highly regulated environment has resulted in lower profitability and return on capital than in many other industrial sectors. In the regulated marketplace the level and margin of profitability has often primarily been a function of regulatory leeway, with the contribution of operating efficiency and revenue growth taking more of a back seat.

Deregulated/liberalized environments. In deregulated markets, cost efficiency and flexibility, and internal growth, are the major profitability drivers. The development of a robust risk management culture and infrastructure are also keys to creating stability of earnings, because the company no longer has recourse to the regulator to cover costs or losses—a recourse that usually protects from downside earnings surprises in the regulated sector.

Whether generated by the regulated or deregulated side of the business, profitability is critical for utilities because of the need to fund investment-generating capacity, maintain access to external debt and equity capital, and make acquisitions. Profit potential and stability is a critical determinant of credit protection. A company that generates higher operating margins and returns on capital also has a greater ability to fund growth internally, attract capital externally, and withstand business adversity. Earnings power ultimately attests to the value of the company's assets, as well. In fact, a company's profit performance offers a litmus test of its fundamental health and competitive position. Accordingly, the conclusions about profitability should confirm the assessment of business risk, including the degree of advantage provided by the regulatory environment.

Part 2—Financial Risk Analysis

Having evaluated a company's competitive position, operating environment, and earnings quality, our analysis proceeds to several financial categories. Financial risk is portrayed largely through quantitative means, particularly by using financial ratios.

We analyze five risk categories: accounting characteristics; financial governance/policies and risk tolerance; cash flow adequacy; capital structure and leverage; and liquidity/short-term factors. We then determine a score for overall financial risk using the following scale:

Table 3 | Download Table

Financial Risk Measures

Description	Rating equivalent
Minimal	AAA/AA
Modest	A
Intermediate	BBB
Aggressive	BB
Highly leveraged	B

The major goal of financial risk analysis is to determine the quality of cash resources from operations and other major sources available to service the debt and other financial liabilities, including any new debt. An integral part of this analysis is to form an understanding of the debt structure, including the mix of senior versus subordinated, fixed versus floating debt, as well as its maturity structure. It is also important to analyze and form an opinion of management's financial policy, accounting elections, and risk appetite. Using cash flow analysis as a building block, it is further necessary to establish the company's liquidity profile and flexibility. While closely interrelated, the analysis of a company's liquidity differs from that of its cash flow as it also incorporates the evaluation of other sources and uses of funds, such as committed undrawn bank facilities, as well as contingent liabilities (e.g., guarantees, triggers, regulatory issues, and legal settlements).

1. Accounting characteristics

Financial statements and related footnotes are the primary source of information about a company's financial condition and performance. The analysis begins with a review of accounting characteristics to determine whether ratios and statistics derived from the statements adequately measure a company's performance and position relative to those of both its direct peer group and the universe of industrial companies. This assessment is important in providing a common frame of reference and in helping the analyst determine the quality of disclosure and the reliability of the reported numbers. We focus on the following areas:

- Analytical adjustments and areas of potential concern;
- Significant transactions and notable events that have accounting implications.
- Significant accounting and financial reporting policies and the underlying assumptions.
- History of nonoperating results and extraordinary charges or adjustments and underlying accounting treatment, disclosure, and explanation.

2. Financial governance/policies and risk tolerance

The robustness of management's financial and accounting strategies and related implementation processes is a key element in credit risk evaluation. We attach great importance to management's philosophies and policies involving financial risk.

Financial policies are also important because companies with more conservative balance sheets and the credit capacity to pursue the necessary investments or acquisitions gain an advantage. Overly aggressive capital structures can leave very little capacity to absorb unexpected negative developments and will certainly leave little capacity to make future strategic investments. Companies with the credit capacity to support strategic investments will be better positioned to both evolve with industry change and to withstand inevitable downturns.

Understanding management's strategy for raising its share price, including its financial performance objectives, e.g., return on equity, can provide invaluable insight about the financial and business risk appetite.

3. Cash flow adequacy

Cash-flow analysis is one of the most critical elements of all credit rating decisions. Although there usually is a strong relationship between cash flow and profitability, many transactions and accounting entries affect one and not the other. Analysis of cash-flow patterns can reveal a level of debt-servicing capability that is either stronger or weaker than might be apparent from earnings. Focusing on the source and *quality/volatility of cash flow is also important* (e.g., *regulated/deregulated*; generation/transmission/trading).

A review of cash flow historically, as well as needs on a forward-looking basis, should take into account levels of capital expenditures for new generation plants. In periods where elevated new construction occurs in anticipation of a rise in power demand, cash outflows will be high.

It is particularly important to evaluate capital-intensive businesses, such as utility companies, on the basis of how much cash they generate and absorb. Debt service is an especially important use of cash flow.

Cash-flow ratios. Ratios show the relationship of cash flow to debt and debt service, and also to the company's needs. Because there are calls on cash flow other than repaying debt, it is important to know the extent to which those requirements will allow cash to be used for debt service or, alternatively, lead to greater need for borrowing. The most important cash flow ratios we look at for the investor-owned utilities are:

- Funds from operations (FFO)/Total debt;
- FFO/Income;
- Funds from operations/Total debt (adjusted for off-balance-sheet liabilities);
- EBITDA/Interest; and
- Net cash flow/Capital spending requirements.

4. Capital structure and leverage

For utilities, the long-term nature of capital commitments and extended breakeven periods on investment, make the type of financing required by these companies to finance these needs to be similar in many ways to the financing needs of other long-term asset-intensive businesses. Our analysts review projections of future CAPEX, debt, and FFO levels to make a determination of the likely level of leverage and debt over the medium term, and the companies' ability to sustain them. The valuation of the debt amortization scheduled is tied into projections of profitability breakeven, and the underlying assets becoming cash-flow-positive, are key components of the combined cash flow and leverage analysis.

Capitalization ratios. When analyzing a utility's balance sheet, a key element is analysis of capitalization ratios. The main factors influencing the level of debt are the level of capital expenditures, particularly construction expenditures, and the cost of debt. Companies with strong balance sheets will have more flexibility to further reduce their debt, and/or increase their dividends. The following are useful indicators of leverage:

- Total debt*/total debt + equity; and
- Total debt* + off-balance-sheet liabilities/total debt + off-balance-sheet liabilities + equity.

*Power purchase agreement-adjusted total debt. Fully adjusted, historically demonstrated, and expected to consistently continue.

Debt leverage, and interest and amortization coverage ratios are the key drivers of the financial risk score.

5. Liquidity/working capital/short-term factors:
Our liquidity analysis starts with operating cash flow and cash on hand, and then looks forward at other actual and contingent sources and uses of funds in the short term that could either provide or drain cash under given circumstances.

A key source of liquidity is bank lines. Key factors reviewed are total amount of facilities; whether they are contractually committed; facility expiration date(s); current and expected usage and estimated availability; bank group quality; evidence of support/lack of support of bank group; and covenant and trigger analysis. Financial covenant analysis is critical for speculative-grade credits. We request copies of all bank loan agreements and bond terms and conditions for rated entities, and review supplemental information provided by issuers for listing of financial covenants and stipulated compliance levels. We review covenant compliance as indicated in compliance certificates, as well as expected future compliance and covenant headroom levels. Entities that have already tripped or are expected to trip financial covenants need to be subject to special scrutiny and are reviewed for their ability to obtain waivers or modifications need to be subject to special scrutiny and are reviewed for their ability to obtain waivers or modifications to covenants. Tripping covenants can have a double negative effect on a company's liquidity. It may preclude it from borrowing further under its credit line, and may also lead to a contractual acceleration of repayment and increased interest rates.

STANDARD & POOR'S

RATINGSDIRECT®

March 9, 2009

Recovery Mechanisms Help Smooth Electric Utility Cash Flow And Support Ratings

Primary Credit Analyst:
Barbara A Eiseman, New York (1) 212-438-7666; barbara_eiseman@standardandpoors.com

Table Of Contents

Recovery Mechanisms Help Smooth Electric Utility Cash Flow And Support Ratings

Credit markets are tight. Liquidity is constrained. And construction, labor, and material costs are soaring. As if that weren't enough, the U.S. electric utility sector also faces aging infrastructure, declining capacity margins, and increasing environmental compliance requirements. To the extent that utilities increase their capital budgets to address these needs, they will be highly dependent on electricity rate increases to sustain bondholder protection measures. Although construction expenditure forecasts are temporarily lower due to deferrals of some projects, future spending needs will still be significant, especially in light of environmental requirements. And regulatory commissions reviewing material rate increase requests during a time of exceptional economic hardship might be very reluctant to approve higher electric base rates for consumers (as has occurred in Illinois, Michigan, and New York).

For these reasons, we believe innovative ratemaking techniques and alternatives to traditional base rate case applications and large rate hikes will become more critical to the utilities' ability to maintain cash flow, earnings power, and ultimately credit quality. That's why Standard & Poor's Ratings Services views rate recovery mechanisms that allow for the timely adjustment of rates to changing commodity prices and other expenses, outside of a fully litigated rate proceeding, as beneficial to utility creditworthiness.

Regulatory Risk

Regulators have historically set electricity rates that allow utilities to recover their operating costs and earn returns on equity. In our view, a key to the utility's credit quality is a strong, collaborative, and effective working relationship among management, regulators and, increasingly, elected officials to comprehensively vet and understand the risks associated with the utility's recovery of its investment. If the recession extends well into 2010, it is likely to have a credit drag on the sector, especially if utilities come under the inevitable cost scrutiny by regulators. Management's ability to manage this regulatory risk is a critical skill set.

Key factors in our analysis of the regulatory risk are the regulator's track record of consistency, stability, and predictability, as well as efficiency and timeliness. While we recognize the potential economic and political consequences of attempting to significantly raise utility rates during a recession, we believe that from credit perspective, management must work to limit uncertainty in the recovery of a utility's investment. In addition, we believe it must address the issue of rate case lag, especially when engaged in a sizable capital expenditure program. A regulatory jurisdiction that recognizes the importance of cash flow in its decision making process enhances the utility's creditworthiness.

Upon completion of a major project, while a phase-in or rate moderation plan may lessen the burden on the consumer and be more acceptable during an economic downturn, it may impair the utility's credit quality. Slow recovery of costs could further impinge on its liquidity as short-term funds are consumed to finance high working-capital needs. In turn, this may necessitate a larger bank line that increases borrowing costs or increases debt levels to term out the short-term borrowings with medium-term notes, potentially increasing pressure on a company's financial profile. Hence, delayed revenue recovery is likely to be clearly more risky than traditional ratemaking treatment or rate mechanisms that provide timely rate recognition.

In our view, there are ratemaking alternatives that can eliminate, or at least greatly reduce, the issue of rate-case lag, especially when a utility engages in an onerous construction program. Instead of significantly large base rate increases or lengthy rate moderation or phase-in plans, separate tariff provisions that allow for timely rate recognition during construction, without requiring a utility to file a formal rate case application, can gradually ease higher costs into rates, limiting the accumulation of financing costs. Such provisions can also enhance cash flow and earnings stability.

Don't Forget The Fuel

Of primary importance to rating stability is limiting exposure to variations in fuel and purchased power costs, which constitute a utility's most significant expense. These expenses are largely out of utility management's control. Utilities that operate under rate moratoriums, fixed-fuel mechanisms, or significant regulatory lag, or without fuel and purchased-power adjustment clauses, are at risk for fluctuations in fuel and purchased power costs. As a result, they may be subject to reduced operating margins, and greater cash flow volatility and demand for working capital. Companies that are granted fuel true-ups may be required to stretch out recovery over many years to ease the pain for the consumer. There is no guarantee at some distant future date that collection of deferred revenues will occur. Changes in regulators, elected officials, and the economics of the service territory may render the promised recovery less certain.

Standard & Poor's notes that fuel adjustment clauses have become much more common in the utility industry, and several jurisdictions have recently reinstated previously abolished fuel clauses, but not all are created equal. While some states--such as Florida, Iowa, Kansas, and New York--permit recovery on a dollar-for-dollar basis over a defined time period, certain jurisdictions--such as Vermont and Washington State--impose deadbands in which the company absorbs all the risk and rewards of fuel costs above and below the established recovery rate. Beyond the deadband there is a sharing of risks and rewards with ratepayers. Cost recovery mechanisms that permit frequent updating of any estimated costs may help to keep any deferred balance to a relatively small amount.

Construction Is Accelerating

In addition to fuel-cost recovery filings, regulators likely will have to be addressing significant rate increase requests related to new large generating capacity additions, infrastructure and reliability upgrades, and environmental modifications. Current cash recovery and/or return by means of construction work in progress may mitigate the significant cash flow drain and reduce the utility's need to issue debt securities during the construction cycle. States such as Colorado, Idaho, Kansas, South Carolina (for nuclear facilities), North Dakota (for investments in transmission infrastructure and environmental compliance), and Wisconsin allow utilities to employ this credit-supportive ratemaking mechanism for certain projects. Allowing recovery of projected costs with subsequent periodic updates for actual results limits risk for fluctuating costs that occur between rate cases and reduces lags in cost recovery. Examples of less credit-supportive adjustment mechanisms include those that are triggered only after a company's incremental costs reach high thresholds (e.g. Washington) or those that, once triggered, force a company to accumulate significant deferrals before implementing a surcharge that results in real cash. Weak adjustment mechanisms may also cap accumulated deferrals or surcharges between rate cases.

In view of the risks associated with adding new base load capacity, utility managements are avoiding building facilities until absolutely necessary and only with binding regulatory assurances. From a credit perspective, we view the ability of the utility, commission staff, consumer advocates, and other major interveners to reach agreement on need, costs, and cost recovery before construction of new base load capacity as favorable. Iowa, Kansas, and Wisconsin have used preapproval or advance determination of the ratemaking principles for the recovery of certain investments, thereby potentially eliminating a large degree of uncertainty related to this issue.

An increasing number of regulatory jurisdictions are adopting tracking mechanisms and other riders that allow companies to adjust retail rates to reflect capital costs associated with environmental compliance equipment. These mechanisms eliminate the need to file a formal rate application to capture rate base additions and in many instances permit a return on, and of, capital on current and planned projects. Florida, Kansas, Indiana, Minnesota, and Texas are among those states that have adopted environmental tracking mechanisms and other riders that allow companies to reflect in rates capital costs associated with emission controls.

Earnings and cash flow volatility potentially can be reduced and creditworthiness enhanced when a company has the authority to timely recover unanticipated costs, such as those incurred for repairing extraordinary storm damage, as in Florida. While the Alabama Public Service Commission does not currently employ a separate storm repair cost recovery mechanism to ensure rapid recovery of storm repair costs, we believe it has shown a willingness to work with utilities and has authorized increased charges to provide for the recovery of storm restoration expenses on a timely basis and to start replenishing storm reserves.

Rate mechanisms that mandate earnings sharing between shareholders and consumers compensate well run companies with a share of the profits when they earn more than their allowed return on equity. Accordingly, California has implemented an incentive framework that allows utilities to keep a portion of the net savings achieved under their energy efficiency programs. This gives an incentive to make the companies' operations more efficient. In some cases, sharing mechanisms also may provide downside protection to bondholders and can partially shield companies during troubled times by requiring consumers to foot the bill for a portion of lost earnings.

The ability to collect a consistent cash stream, regardless of a service area's weather conditions, provides an important level of stability. Several warmer-than-normal winters or cooler-than-normal summers could impair a utility's financial profile unless weather normalization measures are in place. Such protection can be achieved via a normalization clause or rate design. Some companies without such provisions have seen their financial profiles weaken partially in response to significant adverse weather conditions.

Some regulators and utilities want to significantly increase energy efficiency and conservation programs. Programs designed to separate earnings from delivered volumes (decoupling) can eliminate a current major disincentive for utilities to develop such conservation programs. Traditionally, when people use less electricity, utilities lose revenue. This would also theoretically align the interest of consumers and utilities by implementing innovative rate designs that would not discourage energy conservation and efficiency. For example, in 2008, the Massachusetts Department of Public Utilities issued a ruling that ordered utilities to pursue full decoupling in their next base rate case filings. The order is intended to encourage alternative energy resources and energy conservation and efficiency and to reduce costs without hurting a utility's bottom line.

There are a host of other rate mechanisms or special tariffs that regulatory jurisdictions apply to allow for timely recovery of costs including those associated with transmission, bad debt, property taxes, pensions, infrastructure or bare steel replacement, and legislatively mandated energy efficiency and renewable resource projects. Finally, the greater the percentage of a utility's rates that it recovers through fixed charges rather than volume-based charges, the greater the support for credit quality. And, given the current recession, the application of these various rate mechanisms and techniques, in our view, can be crucial in sustaining creditworthiness for the utility while potentially reducing the risk of evading significant rate increases or rate shock to the customer.

Note: Standard & Poor's recently published Assessments Of Regulatory Climates for U.S Investor-Owned Utilities (Nov. 25, 2008) has identified Alabama, California, Florida, Georgia, Indiana, Iowa, South Carolina, and Wisconsin, as those deemed 'more credit supportive', and Idaho, Kansas, and Kentucky among those 21 jurisdictions characterized as 'credit supportive'. We factored many of the aforementioned rate recovery mechanisms as well as other ratemaking and financial stability factors and political considerations into these assessments.

HECO T-7
DOCKET NO. 2008-0303

TESTIMONY OF
PETER C. YOUNG

DIRECTOR, PRICING DIVISION
ENERGY SERVICES DEPARTMENT
HAWAIIAN ELECTRIC COMPANY, INC.

SUBJECT: Time-of-Use Rates

INTRODUCTION

Q. Please state your name and business address.

A. My name is Peter C. Young and my business address is 220 South King Street, Suite 1201, Honolulu, Hawaii.

Q. By whom are you employed and in what capacity?

A. I am Director of the Pricing Division of the Energy Services Department at the Hawaiian Electric Company, Inc. ("Hawaiian Electric" or the "Company"). My experience and background are listed in HECO-700.

Q. What is your area of responsibility in this testimony?

A. My testimony in HECO T-7 will address the proposed time-of-use ("TOU") rates of Hawaiian Electric, Hawaii Electric Light Company, Inc. ("HELCO") and Maui Electric Company, Limited ("MECO") (collectively, the "Hawaiian Electric Companies" or "Companies"), the testimonies of the Division of Consumer Advocacy ("Consumer Advocate"), the Hawaii Renewable Energy Alliance ("HREA") and Life of the Land ("LOL") regarding TOU rates, and the Commission's information requests regarding TOU rates.

HAWAIIAN ELECTRIC COMPANIES' PROPOSED TOU RATES

Q. What is the Hawaiian Electric Companies' request in this docket with respect to TOU rates?

A. The Companies' request expedited approval of proposed Schedule TOU-R (Residential TOU) rates for all Hawaiian Electric Companies, and proposed Schedule TOU-G (Small Commercial TOU Service), Schedule TOU-J (Commercial TOU Service) and Schedule TOU-P (Large Power TOU Service) rates for HELCO and MECO, as described in Exhibit 25 of the Advanced Metering Infrastructure ("AMI") Application.

Q. What is the current status of TOU rate options at the Hawaiian Electric Companies?

A. TOU rate options are available for all Hawaiian Electric customers, as approved in Hawaiian Electric's 2005 test year rate case (Docket No. 04-0113). Similar TOU options are proposed in the currently open HELCO 2006 test year rate case (Docket No. 05-0315) and MECO 2007 test year rate case (Docket No. 2006-0387).

Q. What is the proposed residential TOU rate option for the Hawaiian Electric Companies?

A. As described in Exhibit 25 of the AMI Application, the rate design of the Schedule TOU-R proposed in the Hawaiian Electric 2009 test year rate case (Docket No. 2008-0083) (which includes two TOU rate periods and a five hour daily on-peak period) is the rate form proposed for the residential TOU rate option for all of the Hawaiian Electric Companies in this docket. The Schedule TOU-R rates proposed for the Companies in this docket are based on the costs in the most recent rate case applications for each company (i.e., Hawaiian Electric 2009 test year, HELCO 2006 test year and MECO 2007 test year). The Hawaiian Electric Companies also request that the proposed residential TOU rate options, if approved, supersede the residential TOU rate proposals in the open rate cases for HELCO's 2006 test year, Hawaiian Electric's 2007 test year (Docket No. 2006-0386), and MECO's 2007 test year, where the Schedule TOU-R rate options proposed for residential customers have three TOU rate periods.

Q. What are the proposed commercial TOU rate options for HELCO and MECO?

A. The proposed commercial TOU rate options for HELCO and MECO are based on the rate option forms proposed in the HELCO 2006 test year rate case and MECO

2007 test year rate case, respectively, and the rate levels are based on the settlement agreements achieved in those rate cases. HELCO and MECO also request that the proposed TOU rate options for commercial customers in this docket remain in place and supersede the commercial TOU rate proposals in the open rate cases for HELCO's 2006 test year and MECO's 2007 test year.

Q. How does the Energy Cost Adjustment Clause affect the proposed TOU rates?

A. The Hawaiian Electric Companies have adjusted the rate levels in the proposed TOU rate options to be consistent with the current energy cost adjustment clause at each utility.[1] The Companies will submit revised TOU rate option proposals for residential and commercial customers to re-price the rates to be consistent relative to the regular rate schedule rates and the energy cost adjustment clauses that the Commission approves in final decisions in the open rate cases for the HELCO 2006 test year, Hawaiian Electric 2007 test year, MECO 2007 test year, and Hawaiian Electric 2009 test year.

Q. Are there limits on participation in TOU rate options?

A. In the existing Hawaiian Electric TOU rate options as well as in the proposed TOU rate options in the HELCO 2006 test year, Hawaiian Electric 2007 test year, MECO 2007 test year, and Hawaiian Electric 2009 test year rate cases, there are explicit customer limits for participation in TOU rate options until a new billing system is in place that is capable of processing TOU bills. The limits are proposed in order to manage the Companies' ability to deliver timely bills for TOU rate option customers, since all of those bills must be calculated and processed manually. The TOU rate options proposed in this docket do not contain

[1] The energy cost adjustment clause at the respective Hawaiian Electric Companies is based on Hawaiian Electric 2005 test year rates, HELCO 2000 test year rates, and MECO 1999 test year rates.

meter limits. The Hawaiian Electric Companies will make their best efforts to accommodate all customers who wish to participate in these TOU rate options. However, the Companies also propose to reserve the right to apply to the Commission for meter limitations if and when the Companies become unable to calculate and deliver TOU bills in a timely manner.

Q. Why are the Hawaiian Electric Companies' proposals for TOU rate options reasonable?

A. The Hawaiian Electric Companies' proposals for TOU rate options are reasonable because they are based on rate case costs (Hawaiian Electric 2009 test year, HELCO 2006 test year and MECO 2007 test year), and the proposed TOU rate designs have been agreed upon in settlement agreements by all parties to those respective rate cases. These rate options provide to customers an opportunity to shift load as a tool to manage their electric bills.

POSITIONS OF THE OTHER PARTIES ON TOU RATES

Consumer Advocate

Q. What is the Consumer Advocate's position on the Hawaiian Electric Companies' proposed TOU rates?

A. The Consumer Advocate does not have any recommended modifications to the proposed TOU rate design forms, and concludes that the TOU rate design forms should be approved by the Commission.[2]

Q. The Consumer Advocate recommends that the Hawaiian Electric Companies' be required to obtain, if the customer is willing, information on why the customer opted out of TOU or dynamic pricing options. Are the Companies willing to do this?

---

[2] CA-T-1, page 45, Docket No. 2008-0303.

A. Yes. The Hawaiian Electric Companies will explore the reasons why customers opt out of TOU or dynamic pricing options, to the extent that customers are willing to identify such reasons, and include them in the annual report pursuant to Section 14, paragraph 7 of the Energy Agreement.

Q. Is the Consumer Advocate's concern that approval of sales decoupling will dilute or effectively mute TOU price signals valid?

A. No. The price signals provided by the proposed TOU rates are not affected by the rate impact of a decoupling adjustment or by the rate impact of any other rate adjustment. The Hawaiian Electric Companies are not proposing that the decoupling rate adjustment or any other rate adjustment change the proposed TOU rates. The value of a kWh or kW that is shifted from one TOU rating period to another or conserved under the proposed TOU rates is not affected by the level of other rate adjustments, which are applied at the same rate throughout all hours of the day.

Q. What is the Consumer Advocate's concern with authorizing a separate AMI surcharge?

A. The Consumer Advocate's concern is that, with many surcharges, it becomes more difficult and complex to reconcile the various revenues, expenses, and rate base elements that need to be considered when evaluating what was recovered through base rates and what is recovered through surcharges.

Q. How do the Hawaiian Electric Companies address the Consumer Advocate's concern?

A. The Hawaiian Electric Companies will provide the necessary information in the filing of the annual reconciliation of revenue requirements and revenues collected. As described in Section XI, pages 68-69 of the AMI Application, the Companies will reconcile the incremental revenue requirements for the previous calendar year's actual capital investments, expenses, and benefits for the AMI Project with revenues collected. The reconciliation adjustment will also reduce the surcharge for the revenue requirements of the AMI Project costs and net benefits that are reflected in approved rates after being included in the revenue requirements of a future rate case. The Companies will calculate such adjustments based on interim decisions and orders received in rate cases, and will further adjust incremental revenue requirements to conform to final decisions and orders in rate cases. The Companies will be able to provide this information whether AMI Project costs are recovered through the Renewable Energy Infrastructure Program ("REIP") Surcharge pending in Docket No. 2007-0416, or through a separate AMI surcharge.

Q. What is the Consumer Advocate's concern regarding the financial impact of the AMI Project?

A. The Consumer Advocate suggests that the financial impact of advancing the AMI Project should be minimized on low income and disadvantaged customers. However, the Consumer Advocate does not suggest how that might be accomplished.

Q. What is the Hawaiian Electric Companies' response to this concern?

A. The Hawaiian Electric Companies believe that the Consumer Advocate's concerns regarding the financial impact of the AMI Project and other proposed projects are addressed by the Companies' lifeline rate proposal. As the Consumer Advocate noted, the Companies filed an application for a Lifeline Rate Program on April 30, 2009 in Docket No. 2009-0096. In Section 20 of the Energy Agreement, the Hawaiian Electric Companies and the Consumer Advocate agreed to explore the possibility of establishing lifeline rates, which are designed to provide a cap on rates for those who are unable to pay the full cost of electricity. The Companies' lifeline rate proposal supports low income families by providing assistance for a minimum level of necessary energy use in the form of a monthly bill credit.[3]

<u>HREA</u>

Q. What is HREA's position on the Hawaiian Electric Companies' proposed TOU rates?

A. HREA proposes that a potential benefit that should be evaluated further is TOU rates for small commercial and large power customers as a "load-shifting" measure. HREA believes that larger customers will be better able to adapt their demand usage patterns than residential customers.

Q. What is the Companies' response to this position?

A. The Companies' TOU rate option proposals do offer TOU rates for small commercial customers as well as large power customers; therefore that would appear to satisfy HREA's concerns.

<u>LOL</u>

Q. What is LOL's position on the Hawaiian Electric Companies' proposed TOU rates?

A. LOL states that it favors TOU rates but needs more information before making a decision on this Application. LOL states that it needs a better understanding of how TOU rates interact with a host of related issues including but not limited to Feed-In Tariffs, Net Metering, PV Host, and Vehicle to Grid.

Q. What is the Companies' response to this position?

---

[3] Docket No. 2009-0096, Application, page 4.

A. The Hawaiian Electric Companies' proposed TOU rate options are available to customers who participate in Net Energy Metering. While TOU rate options address the price customers pay for utility-supplied electricity, the Feed-In Tariff docket (Docket No. 2008-0273) and PV Host docket (Docket No. 2009-0098) are concerned with establishing the price the utility will pay to acquire energy from customers/providers; thus, there is no interaction between TOU rates and Feed In Tariff or PV Host. The Vehicle to Grid issues are in the early stages of examination. It may be that the proposed TOU rates will be compatible with Vehicle to Grid applications; however, the Companies are unable to make any conclusions at this time.

INFORMATION REQUESTS OF THE COMMISSION

Q. Why do the Hawaiian Electric Companies propose that TOU rates be opt-in during the AMI meter roll-out period rather than opt-out or mandatory?

A. The Hawaiian Electric Companies propose that TOU rates be opt-in during the roll-out period in order to reduce the administrative challenges of the billing process while still providing customers the choice to subscribe to TOU rates. During the roll-out period, meter conversions will be affected by installer work rate, schedule changes, and other challenges in the field. Tracking the meter conversions is a significant task. It will be administratively easier to adjust customer rate schedules after all the AMI meters have been placed. However, the Companies recognize that TOU rate options will likely be available to customers both before and during the roll-out period, and the Hawaiian Electric Companies will accommodate those customers who elect TOU rates.

Q. After the general AMI roll-out, do the Hawaiian Electric Companies propose that

TOU rates be opt-in, opt-out or mandatory, for non-commercial customers?

A. The Hawaiian Electric Companies are still considering how TOU rates would apply to non-commercial customers after the general AMI roll-out. The Hawaiian Electric Companies have not yet assessed the potential impact to customer bills and how different groups of non-commercial customers (for example low energy users, average energy users, and high energy users) are affected by TOU rates. The Hawaiian Electric Companies will consider applying TOU rates on a mandatory basis to non-commercial customers.

Q. Have the Hawaiian Electric Companies considered or attempted to quantify the difference in participation rate and peak demand reduction for scenarios in which TOU rates are (a) opt-in, (b) opt-out, or (c) mandatory for all customers? If so, please provide the results of any such studies or analysis.

A. The Hawaiian Electric Companies have not studied the difference in participation rate and peak demand reduction between TOU rate implementations that are opt-in, opt-out, or mandatory.

Q. Why do the Hawaiian Electric Companies propose that TOU rates for commercial customers be mandatory rather than opt-out, at the completion of the AMI roll-out?

A. The Hawaiian Electric Companies propose that TOU rates for commercial customers be mandatory at the completion of the AMI roll-out because it is expected that the TOU rates will provide price signals for efficient energy consumption. The AMI Network is expected to provide information on customer energy usage such that commercial customers can effectively respond to the TOU rates, manage their energy consumption, and reduce their electric bills, if they choose to do so. The Companies prefer not to offer customers an option where the pricing signal may be less clear and where the resulting energy consumption may be less efficient.

SUMMARY

Q. Please summarize your testimony.

A. The Hawaiian Electric Companies request expedited approval of proposed Schedule TOU-R (Residential TOU) rates for all Companies, and proposed Schedule TOU-G (Small Commercial TOU Service), Schedule TOU-J (Commercial TOU Service) and Schedule TOU-P (Large Power TOU Service) rates for HELCO and MECO. The Companies' proposals for TOU rate options are reasonable because they are based on rate case costs (Hawaiian Electric 2009 test year, HELCO 2006 test year, and MECO 2007 test year), and the proposed TOU rate designs have been agreed upon in settlement agreements by all parties to those respective rate cases. These rate options provide to customers an opportunity to shift load as a tool to manage their electric bills.

The Consumer Advocate's concern that approval of sales decoupling will dilute or effectively mute TOU price signals is not valid. The price signals provided by the proposed TOU rates are not affected by the rate impact of a decoupling adjustment or by the rate impact of any other rate adjustment.

The Consumer Advocate's concern about the difficulty and complexity of reconciling the various revenues, expenses, and rate base elements is addressed by the Companies' provision of the necessary information in the filing of the annual reconciliation of revenue requirements and revenues collected. The Companies will be able to provide this information whether AMI Project costs are recovered through the REIP Surcharge or through a separate AMI surcharge.

The Hawaiian Electric Companies propose that TOU rates be opt-in during the roll-out period in order to reduce the administrative challenges of the billing process while still providing customers the choice to subscribe to TOU rates. The Companies are still considering how TOU rates would apply to non-commercial customers after the general AMI roll-out. The Companies propose that TOU rates for commercial customers be mandatory at the completion of the AMI roll-out because it is expected that the TOU rates will provide price signals for efficient energy consumption. The AMI Network is expected to provide information on customer energy usage such that commercial customers can effectively respond to the TOU rates.

Q. Does this conclude your testimony?

A. Yes it does.

HAWAIIAN ELECTRIC COMPANY, INC.

PETER C. YOUNG

EDUCATIONAL BACKGROUND AND EXPERIENCE

BUSINESS ADDRESS:	Hawaiian Electric Company, Inc. P.O. Box 2750, Honolulu, Hawaii 96840
CURRENT POSITION:	Director, Pricing Division Energy Services Department
YEARS OF SERVICE:	21 Years
OTHER EXPERIENCE:	Financial Analyst, Pacific Resources, Inc. Corporate Analyst, Pentagram, Inc.
EDUCATION:	MBA (Finance), University of Washington BA (Economics, Political Science), Claremont McKenna College, Claremont, CA
TESTIMONY:	Docket No. 2008-0083 – Total Operating Revenue; Cost of Service and Rate Design (HECO) Docket No. 2007-0346 – Residential Bill Impact (HECO) Docket No. 2006-0387 - Electric Sales Revenue; Cost of Service and Rate Design (MECO) Docket No. 2006-0386 - Electric Sales Revenue; Cost of Service and Rate Design (HECO) Docket No. 05-0315 - Electric Sales Revenue; Cost of Service and Rate Design (HELCO) Docket No. 05-0146 – Residential Rate Reduction Program; Revenue Requirements and Customer Impact (HECO) Docket No. 05-0145 – Revenue Requirements and Customer Impact (HECO) Docket No. 04-0113 - Electric Sales Revenue; Cost of Service and Rate Design (HECO) Docket No. 99-0207 - Electric Sales Revenue; Cost of Service and Rate Design (HELCO) Docket No. 97-0346 - Electric Sales Revenue; Cost of Service and Rate Design (MECO) Docket No. 7766 - Rate Base (HECO) Docket No. 7764 - Rate Base (HELCO) Docket No. 7700 - Rate Base (HECO)